National Grid Electricity Transmission Network Asset Risk Annex for RIIO-T3

NARA-T3 I Issue 7

01/08/2024

Issue Record

Issue	Date	Summary of Changes
1	30/04/2018	Ofgem Submission
2	18/05/2018	Public Consultation
3	29/06/2018	First live version
3.1	02/11/2018	Incorporating changes following Calibration, Testing & Validation (CTV)
4	24/08/2020	Updates to system consequence and OHL scoring methods
5	25/03/2021	Update to CB C1 factor. Updates to Cable scoring method. New material concerning application of Long Term Risk Benefit to RIIO-T2.
6	02/12/2022	Major update of document including: • Transfer to new document template • New introductory material • Merge of Licensee-specific appendices into main text following NARM Methodology Review exercise • Obsolete references to NOMs replaced with NARM
6.1	14/07/2023	Update to HSE ALARP Check advice. Minor modifications post consultation on issue 6 for clarity.
7 (draft)	TBC	Scope of changes leading into RIIO-T3 Significant changes to Boundary Capability assessment for System Consequences Update to Cable Scoring methods Updates to OHL Scoring methods TO Common Safety, Environmental & Financial Consequence elements LTRB Immortal Model Renumbered equations by document section number

Contents

Purpose

This document outlines the role of Monetised Risk in the context of providing a quantified, consistent, and measured approach to network investment.

By the commencement of RIIO-T3, NGET will have completed two price controls using the concept of monetized risk in a decision support role, and one with Long Term Risk Benefit as a key output linked to funding mechanisms.

This issue of the Network Asset Risk Annex (NARA) is intended to inform the development of the RIIO-T3 price control. This is separate from documentation applying to RIIO-T2, to facilitate development without impact on T2 outcomes, that are dependent on features in earlier issues (NARA v6.1).

The Network Asset Risk Annex describes the calculation and application of Monetised Risk for the following asset categories:

- Circuit Breakers
- Transformers
- Reactors
- Underground Cables (Transmission)
- Overhead Line Fittings

NGET, UK Transmission Networks, and electricity networks worldwide are undergoing unprecedented change. The advancement of net zero goals; unprecedented numbers of connection requests, demand for electric vehicles, Heat Pumps, A/C, and new generation and storage capabilities are all significant factors. Proportionally, NGET anticipates the next 10 to 20 years of investment attention to shift onto the facilitation of these demands. However, new assets need a reliable and safe network to connect to. The Network Asset Risk Metric (NARM) is part of the toolset NGET uses to make effective decisions in this space.

As network investment takes place over the longer term, there would be a time lag before any under-investment in the assets would impact the primary outcomes (reliability and delivery of power). For example, if an asset is not replaced when required, it still may be some time until the asset impacts network reliability. The use of monetised risk means that the TO can identify and prioritise interventions needed to maintain a safe and reliable network; informing choices of part-replacement, refurbishment, or aid in justification for full-substation replacement. NARM has demonstrable applications concerning substation and network topology and will continue to inform asset health related decisions.

Transmission License Special Condition 9.2 sets out the requirements of the licensee in respect of the NARM Methodology. It also sets out the process for modifying the NARM Methodology.

Scope of Changes for RIIO-T3

This update of the NARA is to update the monetised consequence values into a 2023/24 price base, evolved in response to stakeholder feedback and addressing future needs. The overarching priority is to identify asset intervention requirements. Where features are no longer perceived to be useful, these will be discontinued.

We have revised the approach to determining System Consequences associated with Boundary Costs. The prior method incurred a considerable overhead on ESO to supply economic modelling to inform these costs; of the order of several months work. Provisions for this data exchange have been codified in STCP21-2; however, in the interests of reducing the overhead of operation, this issue includes a revised method. It still produces comparable outputs, but it can be more readily updated, and consider more boundaries, if desired, while avoiding most of the ESO overheads, by using data from ETYS that will continue to be produced.

NGET have revised the approach to Environmental Consequences to account for alternatives to SF6 becoming commercially available. Updated carbon costs have been applied to the environmental consequence values, as well as inflated to reflect a 2023/24 price base. Financial and Safety consequences have been revised with respect to inflation; and; where possible, aligned to common values used by all three ETO's.

NGET acknowledge the need for long-term thinking to drive TO and cross-sector behaviour. However, the earlier LTRB Analytical Model as-implemented on NARA v6.1, has, in hindsight, proven to have limitations. The survival model was a volatile measure, particularly in respect of maintenance activities; and the NGET implementation did not align to that used by the other TO's or DNO's.

Given the lack of transparency and utility of the analytical model, NGET have replaced the analytical model with a simpler, immortal LTRB model. This uses the same principles as the models used by Electricity Distribution; and is known to be able to eliminate some of the shortcomings of the previous system. It should be noted that the Immortal model's output is of a different order of magnitude. The direct comparison of output from one to the other is not applicable.

The treatment of OHL Fittings and delivery of Targeted Fittings resulted in known issues with NARM reporting mechanics in both RIIO-T1 and -T2. The determination of risk for a given routelet is still possible and a useful tool in its own right; however complications in reporting arise where targeted works do not (and should not) reset the risk associated with a given routelet entirely to zero. This leads to an indicated under-performance, when in fact the targeted intervention is achieving its objectives to minimise cost to consumer while maintaining asset performance at acceptable levels. The OHL EOL equations have been modified to attempt to redress these impacts.

1 The Network Asset Risk Metric objectives

The NARM objectives are detailed in the NARM Common Methodology. They are repeated here for reference.

- To allow Ofgem and other stakeholders to understand the links between the data that a network company collects and utilises and the asset management and investment decisions it makes.
- To enable Ofgem to set outputs for the network company to deliver over a price control period and to ensure that what the network actually delivers can be compared to the targets on a like-for-like basis.
- To enable the network company to estimate the Monetised risk of its network assets both now and in the future.
- To enable the network company to estimate the monetised risk benefit that would be delivered by different types of interventions on any given asset or group of assets. The objective is to be able to estimate single year snapshot risk, and long-term risk benefit.
- The estimated monetised risk benefits should be suitable for use as inputs in Cost Benefit Analyses (CBA) in order to help network companies, choose the best value for money investments, and to demonstrate to Ofgem, consumers and other stakeholders that any investment plans have been optimised. This means that the Monetised Risk Benefits should be realistic with robust probability estimates and correctly valued consequences.
- To enable the identification and quantification of drivers of changes in Monetised Risk over time.
- To allow Monetised risk comparisons to be made between different assets and different networks. In order for this objective to be achieved, the methodologies used for estimating monetised risk should be based as little as possible on subjectivity.
- To enable the network company to report to Ofgem and other stakeholders in a way that can be easily understood and unambiguously interpreted.

2 The Network Asset Risk Annex (NARA) Objectives

NARA-T3 describes the future National Grid ET implementation of the Network Asset Risk Metric (NARM). This document has been renamed to differentiate it from the NARA applicable to RIIO-T2 reporting.

The primary objectives of the document are to explain the mechanics of NGET's risk model, which is used to facilitate the NARM objectives. This is intended to aid stakeholders in their understanding of the current practice. Callout boxes like this are shown throughout this document to highlight important features.

Issue 7 of NARA-T3 represents our ongoing efforts to review and improve the NARM Methodology to better facilitate the NARM objectives in accordance with Licence Special Condition 9.2.6. As part of our commitment to continuous improvement, we will continue to develop the NARM methodology and associated documents to provide greater transparency in methodology and models utilised within NARM.

In consultation with both Ofgem and the other Electricity Transmission Licensees, we have agreed objectives for issue 7. These include:

- Evolution of System Consequences modelling
- Further alignment of Financial, Safety and Environmental Consequence values
- The use of CO2 equivalence for alternate greenhouse gases in Environmental consequence
- Responding to stakeholder feedback on previous issues and consultations.
- Updates to the use of Long-term Risk Benefit

In parallel to these activities, improvements to OHL and cable methods are incorporated into this release of the NARA. The primary driver for the modifications in issue 7 are to reduce the reliance on asset age in evaluating condition, where possible.

3 Introduction

This document is intended to be read in conjunction with the NARM Common Methodology.

3.1 National Grid Electricity Transmission

NGET owns the high voltage electricity transmission system in England & Wales. It is primarily comprised of equipment operating from 400 to 132kV; and consists of approximately

- 4,500 miles of overhead line routes
- 900 miles of underground cables
- 262 miles of offshore HVDC cables
- Over 300 substations

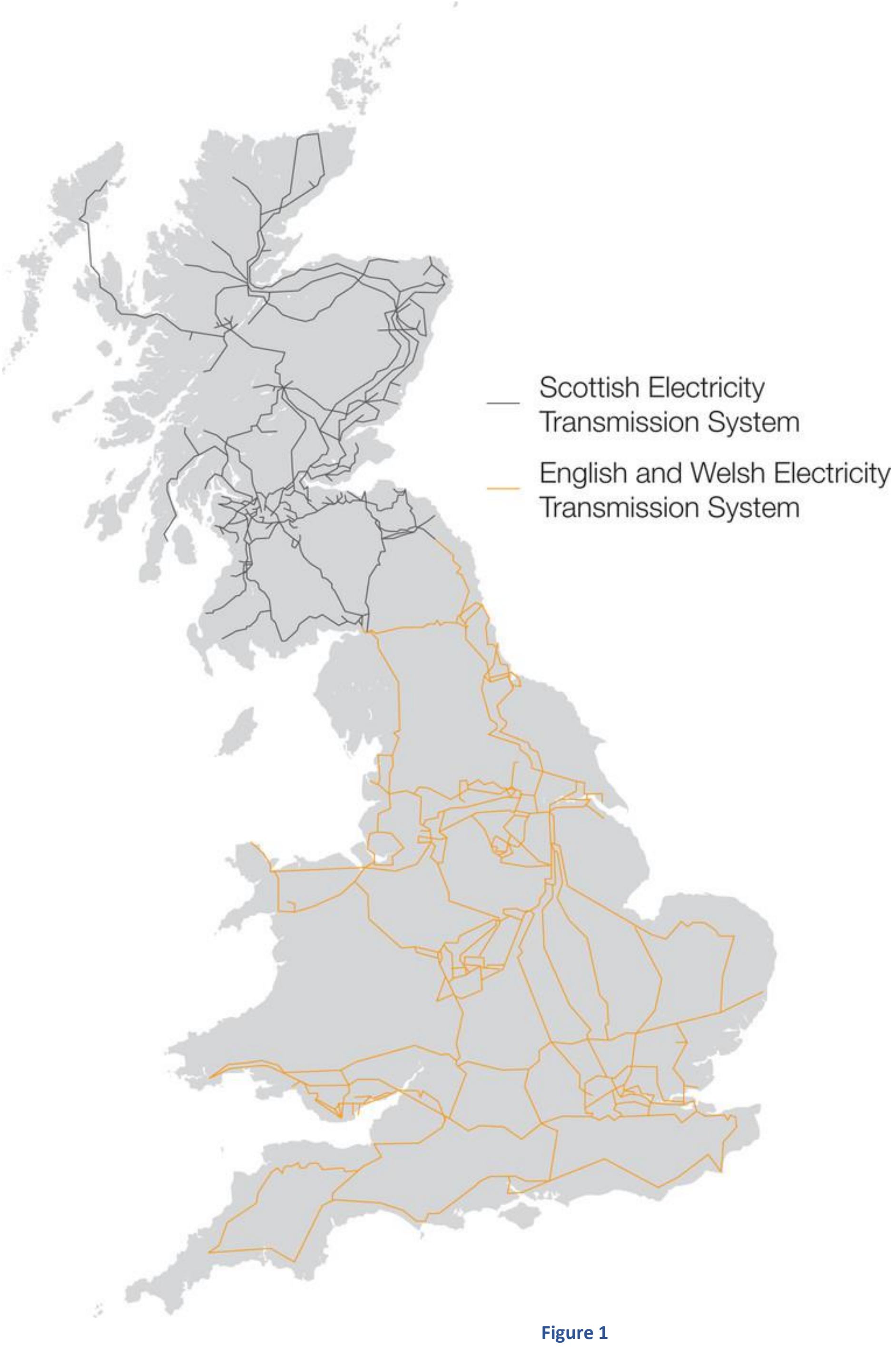


Figure 1

3.2 Introduction to Risk

The formal assessment of risk is a useful tool in managing complex systems. NARM is part of NGET's decision support framework. It has bearing on what interventions (e.g. replacements) take place on the network.

Risk is part of our everyday activities. Whether it is crossing the road or driving our car, we take risk. For these everyday activities we often do not consciously evaluate the risks, but we do take actions to reduce the chance of risk materialising and/or the impact if it does. To reduce the chance of crashing into the car in front, we are taught to leave ample stopping distances for the conditions, and to reduce the impact should a crash happen by fastening our seat belts. These actions are examples of how you can manage risk through mitigation: the risk is modified by action.

The International Organisation for Standardization (ISO) publishes guidance on asset and risk management, in *ISO55001 Asset* Management and related documents.

The ISO standards documents are a foundation upon which one can establish a common basis for identifying, analysing, and modifying risk. *BS EN 60812:2006 Analysis Techniques for System Reliability* provides useful guidance on application of analysis techniques to risk management. Throughout the methodology and NARA-T2, relevant content from these standards have been adopted, including their vocabulary[1]. Some key definitions follow:

Risk	Effect of uncertainty on objectives
Risk management	Coordinated activities to direct and control an organization with regard to risk
Event	Occurrence or change of a particular set of circumstances
Likelihood	Chance of something happening
Consequence	Outcome of an event affecting objectives
Level of risk	Magnitude of a risk or combination of risks, expressed in terms of the combination of consequences and their likelihood

Table 3.1

For NGET, our objectives include keeping the public, staff, and contractors safe; addressing environmental risks and ensuring effective provision of network services. Maintaining a formal process to identify and evaluate risk is beneficial to the transparency of decision making; and optimisation & justification of those decisions.

Risk is often expressed in terms of a combination of the likelihood of an event (including changes in circumstances) and the consequences of the event. Likelihood of an event can be defined mathematically in the form of a probability, or frequency over time; or qualitatively e.g. low/medium/high. While objective measures can be derived for some failure modes, others may have to be defined qualitatively. Small asset populations, or relatively new asset types are likely to lack statistical confidence or historical evidence to describe behaviour.
The consequences of an event can be certain or uncertain and can have positive or negative effects on objectives. These again, can be expressed qualitatively or quantitatively.

A single event can lead to a range of consequence. Initial consequences can escalate through knock-on effects. The events of 9th August 2019 culminating in the automatic disconnection of demand are an example of how unrelated events in the form of lightning strikes co-inciding with a planned disconnection of generation combined to produce unintended consequences.

[1] *The reproduction of the terms and definitions contained in this International Standard is permitted in teaching manuals, instruction booklets, technical publications, and journals for strictly educational or implementation purposes. The conditions for such reproduction are: that no modifications are made to the terms and definitions; that such reproduction is not permitted for dictionaries or similar publications offered for sale; and that this International Standard is referenced as the source document.*

The combination of likelihood and consequence may be expressed in a risk matrix, where likelihood is placed on one axis, and consequence on the other. The combination of likelihood and consequence might be expressed as:

$$Risk = Likelihood * Consequence$$

Equation 3.1

Noting that if a qualitative scale is chosen, the output of equation 1 might be "Low/Medium/High" multiplied by the consequences.

When using the likelihood expressed as a probability and consequences in terms of costs, using the risk equation returns results in the form of a risk cost. Equation 1 is a utility function which provides a view of the relative risk between other items calculated on a similar basis.

This risk cost is *not* a real pounds value. Outputs cannot be directly compared to financial benefits of a decision. A low-risk item may still require intervention to comply with legal and statutory requirements, such as the F-Gas Regulations, Pressure System Safety Regulations, or the Electricity at Work Act. This is the central argument against the use of NARM directly in funding mechanisms.

Concerning the downstream use of Risk within the future price control with respect to NARM objective 5 : networks and regulators must be cognisant of the capabilities and limitations of the tooling applied. Other factors can and should be taken into account to reach useful decisions.

3.3 Stakeholder Engagement and Change Process for RIIO-T3

NARA is published on National Grid's website: **https://www.nationalgrid.com/nara**

The NARA is an adjunct to the NARM Handbook and Common Methodology, and therefore NARA-T3 effectively becomes an extension of the Transmission License; with change governed by similar processes.

Where a new release is proposed; the new material will be presented on the website for at least one month.

We seek to engage with our stakeholders to effectively understand and reflect the priorities of our stakeholders in our asset intervention assessments, using NARM, which feeds into our network planning, development, and operations. We consider a stakeholder in line with AccountAbility's[2] definition of 'any individual, group of individuals, or organisations that affect and/or could be affected by [our] activities, products or services, and/or associated performance'.

Our stakeholder groups include:
• Enablers such as our regulators, government bodies and National Grid ESO.
• Members of the public.
• Industry partners, local authorities, and other network owners.
• Communities both local and regional.
• Infrastructure and emergency response.
• Customers such as electricity generators, distribution network owners, large demand customers.

We would seek to engage with our stakeholders when changes to the NARM methodology are proposed or being developed. When engaging on the NARM methodology, we carry out a mapping exercise to identify the relevant stakeholders, and those who are best placed to provide insight on the proposed methodology updates. Understanding the stakeholders' knowledge level, of the content, allows us to tailor our engagement, to get the best responses. Stakeholder feedback is collected and presented in a report that is submitted to the Authority. The feedback is then used to shape the methodology, with the documentation and methodology revised where necessary.

[2] AA1000 Stakeholder Engagement Standard (AccountAbility, 2015): https://www.accountability.org/wp-content/uploads/2016/10/AA1000SES_2015.pdf

4 Introduction to NGET Risk Calculation Methodology

This section sets out the formal definitions of terms used throughout the methodology.

The NARM Common Methodology and NGET License Special conditions require the evaluation of risk for the 'NARM asset categories' which are:

- Circuit Breakers
- Transformers
- Reactors
- Underground Cables (Transmission)
- Overhead Line Fittings

Often, one or two dominant failure modes contribute to the majority of risk on an asset; that is, the fastest-deteriorating components define the intervention requirements. Lesser failure modes tend to be inconsequential in the context of replacement planning. Maintenance activities throughout the lifetime of an asset are necessary to ensure those lesser failure modes are managed to realise the useful, economic lifetime of an asset.

This means there is only limited benefit to exhaustive analysis of failure modes in the context of risk. It is not feasible to define every possible failure mode and consequence. For example, third party damage to the assets is not considered in the analysis, for this has no bearing on defining maintenance or pre-emptive replacement decisions. Note that for NGET as a TO, this is in considerable contrast to other UK Utilities implementations, whose primary risks arise from third party interference; and their intervention strategy is dominated by fix-on-fail behaviours. This is a major factor in why it is difficult to compare NARM from network to network; it is absolutely valid that different problems require different strategies to optimally manage.

Assessment is driven primarily by the materiality and consequential information sets derived from experience of owning and operating such assets. High-impact, low-probability events are generally out of scope of utilising Monetised Risk. A negligible likelihood multiplied by infinite consequences give a mathematically undefined output that is not useful to relevant asset management decisions. Similarly, the range of possible high-impact low probability scenarios cannot be usefully bound for purposes of assessing risk.

The NGET implementation of this methodology considers failure modes which have been explored in detail, supported by historical data where available; and estimated where it is not.

4.1 Asset (A)

An asset is defined as a unique instance of one of the above five types of assets. Overhead line and cable routes will be broken into appropriate segments of the route. Each asset belongs to an asset family, and each asset family has one or more failure modes. A failure mode can lead to one or more consequences.

4.2 Material Failure Mode (F)

A failure mode is a distinct way in which an asset or component may fail. Material failure modes are those considered to be materially significant. Failure means it no longer does what it is designed to do and has a significant probability of causing a material consequence. Each failure mode is mapped to one or more failure mode effects.

The list of failure modes modelled is not exhaustive, for it is not feasible to catalogue every possible issue. An intervention for previously unmodelled criteria is therefore always within the realms of possibility.

A given failure mode (F_i) is mapped to at least one consequence (C_j) and a conditional probability that the given consequence will manifest should the failure occur $P(C_j \mid F_i)$.

4.3 Probability of Failure P(F)

The probability of failure represents the probability that a failure mode will occur in the next time period. It is generated from an underlying parametric probability distribution, or failure curve. The nature of this curve and its parameters (i.e. increasing or random failure rates, earliest and latest onset of failure) are provided by Failure

Modes and Effects Analysis (FMEA). The probability of failure is influenced by a number of factors, including time, duty, and condition. This document describes the steps used to determine a probability of failure.

NGET fits most of its failure modes to a two-parameter Weibull distribution; noting that while no model is perfect, this is a useful approximation of behaviours witnessed over time.

4.4 Probability of Detection and Action P(D)

There is a probability that the failure mode may be detected through inspection and action taken before there is a consequence. This is denoted by $P(D_i)$ for a given failure mode, *i*.

The probability of detection and action is included for completeness; however it is not currently included within NGET's Risk Model.

There are a number of techniques that may be used to detect certain failure modes, and these have been captured in the FMEA:

Detection Technique	**Activity**
Periodic inspection	Routine inspection of asset at set intervals.
Alarm/indication/ metering	Automatic systems that monitor certain parameters on equipment and provide an automatic alert, e.g. cable oil pressure monitoring detects the possibility of an oil leak.
Sample monitoring	Periodic sampling to establish specific parameters to determine health of asset, e.g. oil sampling on transformers.
Continuous monitoring	Monitoring equipment installed on specific assets whereby data about their health is recovered, logged, trended, and monitored autonomously. Alerts are generated when thresholds are breached, or when a parameter exceeds X% in a specified time frame.
Periodic operation	Planned operation to ensure that the asset/components/mechanisms function as expected, e.g. periodic operation of circuit breakers.

Table 4.1

5 Consequence (C)

This section defines how the Probabilities and range of Consequences are estimated.

For the calculation of asset risk, each of the underlying system, safety, environmental and financial components are assigned a consequence. This is expressed in financial terms. Each Consequence C_j has one or more Failure Modes F_i mapped to it. A consequence itself can only occur once during the next time period.

5.1 Probability of Consequence P(D)

If Consequence *j* can be caused by *n* failure modes, then the probability of consequence $P(C_j)$ occurring in the next time interval is given by:

$$P(C_j) = 1 - \prod_{i=1}^{n}(1 - P(F_i) \times P(C_j|F_i) \times (1 - P(D_i))$$

Equation 5.1

where:

$P(C_j) = Probability\ of\ consequence\ j\ occurring\ during\ a\ given\ time\ period$

$P(F_i) = Probability\ of\ failure\ mode\ i\ occurring\ during\ the\ next\ time\ interval$

$P(C_j|F_i) = Conditional\ probability\ of\ Consequence\ jgiven\ F_i\ has\ occurred$

$P(D_i) = Probability\ of\ detecting\ failure\ mode\ i\ and\ acting\ before\ C_j\ materialises$

Where failure modes and consequences have a one-to-one mapping i.e. the given consequence will definitely occur if the failure mode occurs, the function P(Cj | Fi) is not required : the Probability of Failure is equal to the Probability of Consequence.

5.2 Common Consequence Values

In earlier issues of NGET NARA, asset family specific consequence values and assumptions were used in respect of System, Safety, Environmental and Financial risks. These were bespoke to each TO, and based upon commercially confidential data that could not be published openly. Adopting common consequence values therefore has benefits with transparency and improving the ability to compare performance.

The bespoke nature of nearly all Transmission network installations means that any value selected to represent the cost of a failure event is incorrect, to some degree – a common value is no more or less likely to be incorrect than the closed data sets used previously. The three TO's have agreed a common set of values to work with for RIIO-T3.

Some elements are bespoke to the nature of each network e.g. time to recover post fault, which is partially a function of geography and accessibility. These are retained from previous issues.

Consequence values have been set in terms of a 2023/24 price base, that is, based on the most complete year available at the time of writing and in line with assumptions used to populate the Business Plan Data Tables.

Details of the various amendments to consequences for T3 modelling purposes follow.

5.3 System Consequence Assumptions

These values have been generated in common with the other TO's. Where inflation is used, a RPI-CPIH value has been used to adjust to the relevant price base. Inputs are sourced from publicly available data, particularly from the ESO and Elexon.

Parameter	Description	Purpose	Units	Proposed Value
VOLL	Value of Lost Load	Quantify economic impact of load not supplied	£/MWh	26,163.79
CSBP	Annual average system buy price	Cost incurred to the system in the short term to meet generation shortfall as a result of a disconnection	£/MWh	183.92
CSMP	Annual Average System Marginal Price	Cost incurred to the system in the medium term to meet a shortfall as a result of a disconnection	£/MWh	181.73
TNUoS	Total annual charge for all generators	Total annual TNUoS charge for all generators	£	842,000,000[3]
C_{TNUoS}	Average hourly generation TNUoS refund	Average hourly generation TNUoS refund =11620[£/MW]/8760[hr].	£/hr	1.34
VT	Hourly disconnection cost for Transport Hubs	Quantify economic impact of disconnecting a transport hub	£/h	2,346,425.90
VE	Hourly disconnection cost for Economic Key points	Quantify economic impact of disconnecting an economic key point	£/h	1,816,587.80
VC	Disconnection cost for sensitive COMAH sites	Quantify economic impact of disconnecting a sensitive COMAH site.	£ / event	21,407,982.57
BY, By+1	Cost impact of having to pay generation constraint payments in order to restrict flow across a system boundary	Cost impact of having to pay generation constraints for intact (BY) and depleted (By+1)	£/h	Varies by boundary – *commercially sensitive*
C_{MVArh}	Cost of procuring MVAr from generation sources	Cost of procuring MVAr from generation sources	£/h	5.81[4]

Table 5.1 – System Consequence Assumptions & Inputs

[3] Final TNUoS Tariffs for 2022/23. National Grid ESO., pp. 4-5. https://www.nationalgrideso.com/document/235056/download
[4] Obligatory Reactive Power Service (ORPS) | ESO (nationalgrideso.com)

The TNUoS value is determined from data given in the *ESO TNUoS tariffs report*. TNuOS can be calculated from the 11.62/kW given in said report, leading to £1.34/hr.

Concerning C_{MVArh}, the period 2021-2023 has demonstrated considerable volatility. Data have been sourced from the ESO's Obligatory Reactive Power Service, concerning the cost of procuring reactive compensation. This value had been largely stable for the 13 years prior. A 5-year average (from April 2019-2024) has been used in common with SPT and SHE-T.

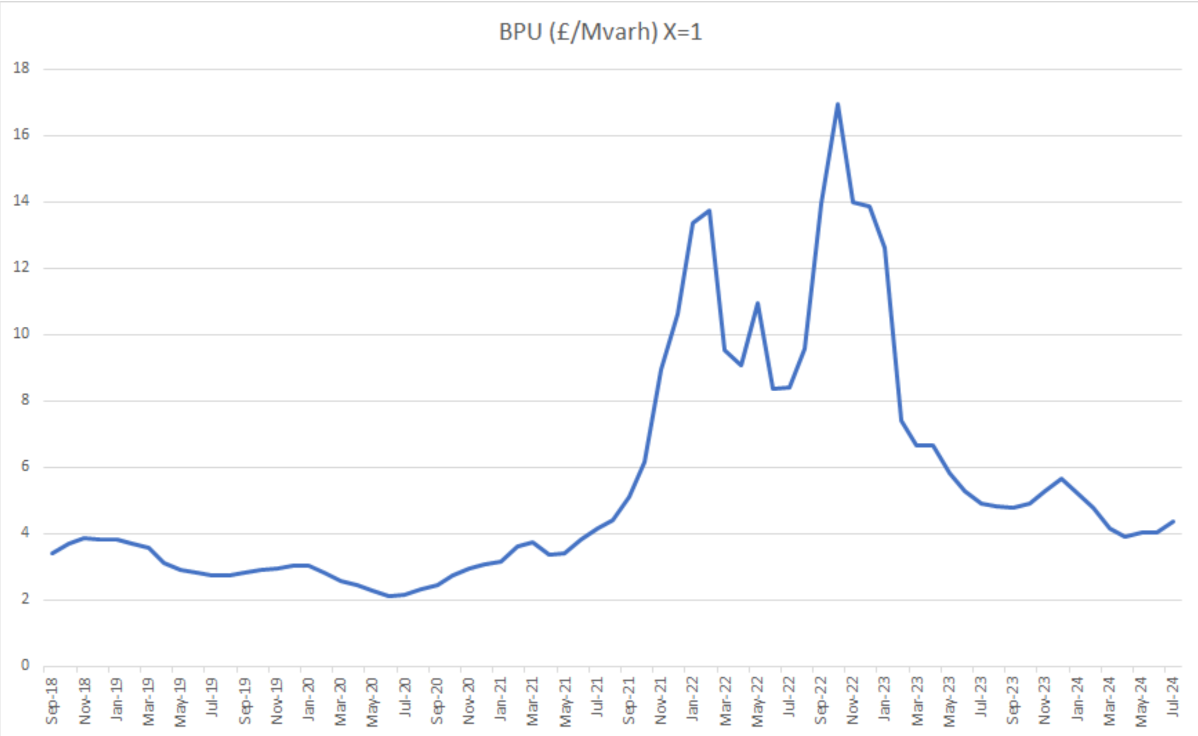


Figure 5.1 – ESO data from the Obligatory Reactive Power Service concerning Cost of Procuring Reactive Compensation

We have no practical means of forecasting this cost. The relative materiality of the reactive consequences component is small, in most cases representing less than 1% of risk on any given asset, therefore the precise choice of value has minimal impact on the model's outputs.

5.4 Environmental Consequence Values

Concerning CO2 equivalence with respect to Carbon Trading Prices, we have utilised values given in Ofgem Greenbook publications. We propose the use of the "high" value case in order to reflect Net Zero ambitions. Adjusting the price base to 23/24 terms, leads to a traded price input of £426/tonne CO2e.

The environmental consequences of gas circuit breakers have been set using the specific asset inventory per breaker, a change from previous issues of NARA. The consequences of this are greater risks attributed to older; high-volume breakers.

NGET have begun to deploy alternative gases to SF6. A multiplier for CO2 equivalence is applied in order to obtain a reasonable estimate for these new types. Green house gas (GHG) CO2 Equivalence estimates vary in available scientific papers for any given gas, therefore, in the interests of consistency, agreed upon values of CO2 Equivalence are recommended for NGET NARA-T3.

The environmental consequences associated with gas volume are specified per asset as ***mass * CO2e * Cost of Carbon.*** Materials currently used, or likely to be used soon on the network are specified for reference.

CO_2 = 1 CO2e / kg
SF_6 = 23,500 CO2e / kg
C4 / G3 = 300 CO2e / kg
100% Nitrogen = 0 CO2e /kg
Clean air = 0 CO2e / kg.

Further discussion of environmental consequences are given in section 8.3.2.

5.5 Financial Consequence Values

NGET have adopted common financial consequences associated with asset replacements. These are aligned to the other TO's. Note that for OHL Fittings, the common value is in £ per fittings set. For compatibility with NGET NARM which is calculated in km, we assume 8 sets per km.

Asset Voltage	Asset Type / unit	Financial Cost
<=132 kV	Circuit Breaker / unit	£400,000
<=132 kV	Transformer / unit	£2,000,000
<=132 kV	Reactor / unit	£4,500,000
<=132 kV	Underground Cable / km	£1,000,000
<=132 kV	OHL Conductor / km	£100,000
<=132 kV	OHL Fittings / km	£320,000
275 kV	Circuit Breaker / unit	£500,000
275 kV	Transformer / unit	£6,000,000
275 kV	Reactor / unit	£6,000,000
275 kV	Underground Cable / km	£2,000,000
275 kV	OHL Conductor / km	£300,000
275 kV	OHL Fittings / km	£400,000
400 kV	Circuit Breaker / unit	£600,000
400 kV	Transformer / unit	£8,000,000
400 kV	Reactor / unit	£6,000,000
400 kV	Underground Cable / km	£3,000,000
400 kV	OHL Conductor /km	£400,000
400 kV	OHL Fittings / km	£480,000

Table 5.2

6 Asset Risk

This section defines how Asset Risk and Network Risk are calculated.

The measure of Asset Risk for a given asset (A) is defined as AR and given by:

$$AR = \sum_{j=1}^{n} PoF_j \times CoF_j$$

Equation 6.1

Where:
$PoF_j = Probability\ of\ Failure\ j\ occurring\ during\ a\ given\ time\ period$
$CoF_j = the\ monetised\ Consequence\ of\ Failure\ j$
$n = the\ number\ of\ failures\ associated\ with\ Asset$

The NGET NARA modifies this slightly. For a given asset k, a measure of the risk associated with it is the Asset Risk (A_k), given by:

$$Asset\ Risk(A_k) = \sum_{j=1}^{n} P(C_j) \times C_j$$

Equation 6.2

Where:
$P(C_j) = Probability\ of\ consequence\ \mathrm{j}\ occurring\ during\ a\ given\ time\ period$
$C_j = the\ monetised\ Consequence\ j$
$n = the\ number\ of\ Consequences\ associated\ with\ Asset\ k$

Figure 2 shows how the many components interact and combine to arrive at a value for an Asset Risk.

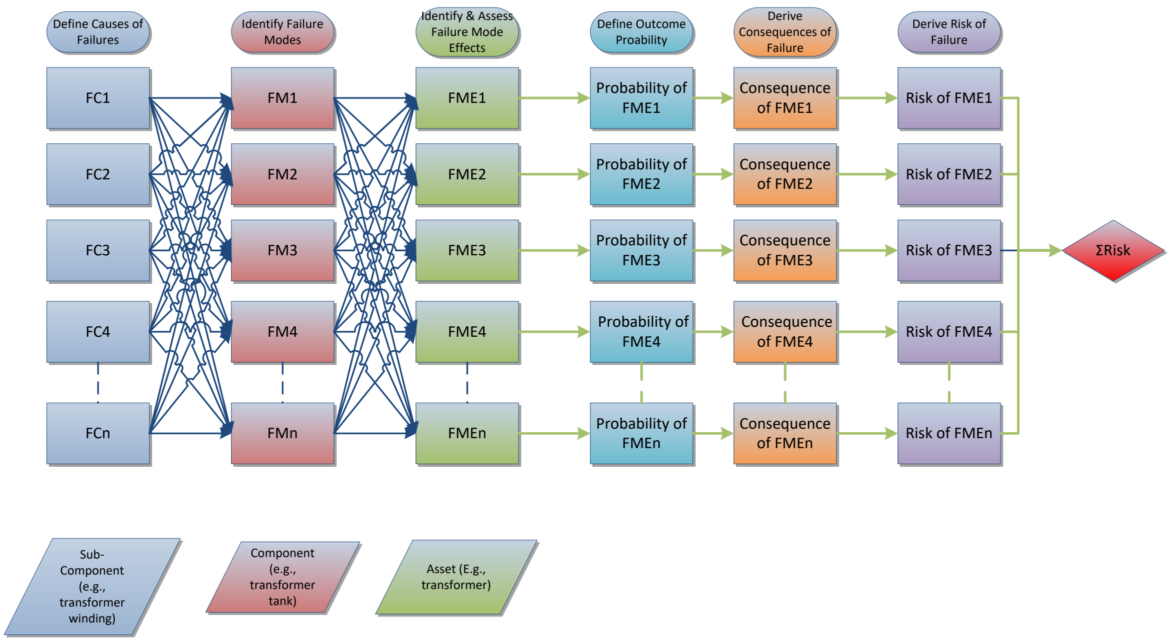


Figure 6.1

6.1 Network Risk

As shown in Figure 2 & Equation 4, the asset risk is a function of the probability of each failure mode occurring, and the impact of each of the consequences.

For reporting purposes, we can sum the individual asset risks to form an estimate of NGET Network risk.

$$Network\ Risk = \sum_{k=1}^{n} A_k$$

Equation 6.3

It should be noted that this is *not* the risk associated with the failure of the entire network, it is the sum of individual asset risks. The consequences of a system-wide failure are not evaluated as part of NARM – this is not useful information in the context of making decisions on single assets.

7 Methodology for Calculating the Probability of Failure

This section discusses techniques used to calculate the probability of failure and forecast future behaviour.

Probability of failure represents the likelihood that a failure mode will occur in the next time period. It is denoted by $P(F_i)$, the probability of failure mode *i* occurring during the next time interval is given by:

$$P(F_i) = S_t - S_{t+1}$$

Equation 7.1

Where:
$P(F_i) = the\ probability\ of\ failure\ mode\ i\ occurring\ during\ the\ next\ time\ interval$
$S_t = the\ cumulative\ probability\ of\ survival\ until\ time\ t$
$S_{t+1} = the\ cumulative\ probability\ of\ survival\ until\ time\ t + 1$

S_t denotes the likelihood that failure does not occur until at least time *t.* It is generated from an underlying parametric probability distribution or failure curve. The nature of this curve and its parameters (i.e. increasing or random failure rate, earliest and latest onset of failure) are provided by the process known as Failure Modes and Effects Analysis (FMEA) as described in BS EN 60812. The probability of failure is influenced by time, duty, and condition.

7.1 Define Causes of Failure

Failure may be defined and categorised in different ways. For the purposes of NGET's FMEA, we consider three basic types of failure:

Time-based failure (potential to functional failure). This assumes that the patterns of failure are predictable within an interval between initiation (potential) and failure. Inspection activities may be available to identify the development of the failure cause after initiation. Time-based failures are represented within the model with an earliest and latest expected onset of failure based on the time that has elapsed following the last intervention (for example, maintenance).

Utilisation failure. Failure is based on duty with a predictable 'useful life' for the component. A preventative intervention can be undertaken, if this useful life is understood, which can be scheduled before failure occurs. For example, these assets may have a known number of operations and are represented by the number of expected operations to failure since the last intervention addressing the particular failure mode.

Random failure. These failures have a constant failure rate, when observed over large enough populations or sufficient periods of time. They are usually expressed as a percentage per annum for the population.

Failure causes are usually determined by analysis of failed assets, testing, and expert's knowledge.

7.2 Identify failure modes

There are multiple potential causes of asset failure. These lead to many different failure modes, which in turn lead to one or more events. Every asset will have many different failure modes, consideration of the range of failure modes associated with a circuit breaker, for example, may resemble figure 3.

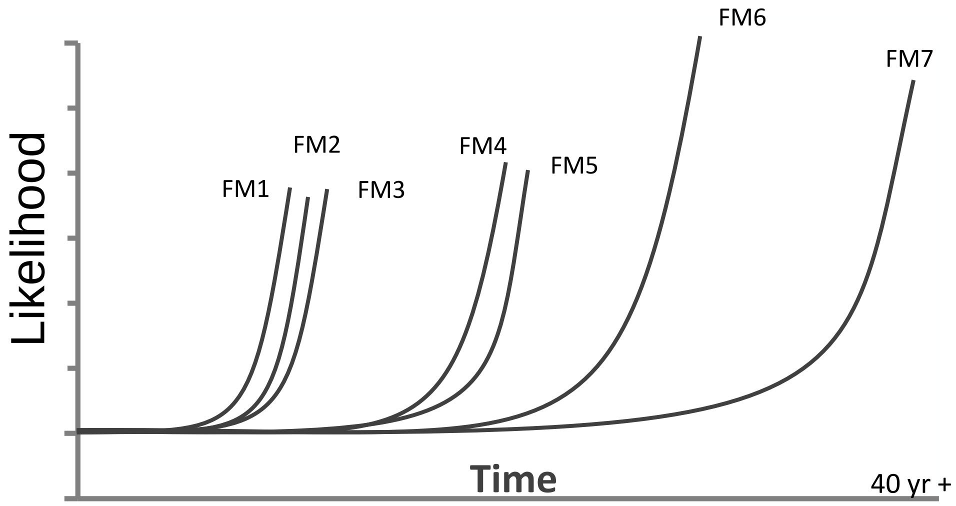


Figure 7.1

Examples might include

FM1	Failure to trip
FM2	Failure to open
FM3	Failure to complete operation
FM4	Failure to close
FM5	Failure to respond to control signal
FM6	Flashover
FM7	Loss of Containment

Table 7.1

The level of detail in the analysis (and number of relevant failure modes) is an important consideration. Section 5.2.2.3 of BS EN 60812 provides useful guidance in this area, recognising that the number of failure modes for consideration will be influenced by previous experience. Less detailed analysis is justified for systems of mature design, good reliability, maintainability, and safety record. In addition, the requirements of asset maintenance and repairs are valuable to determining the necessary level of detail.

7.3 Understanding Failure Modes and How Interventions Impact Asset Risk

Figure 4 shows a simplified example of an asset that has two failure modes (FM1 and FM2). The blue line represents the asset's risk position with time. The risk position on the y axis represents the risk associated with the relevant failure mode. The total asset risk would be calculated as stated in equation 3.

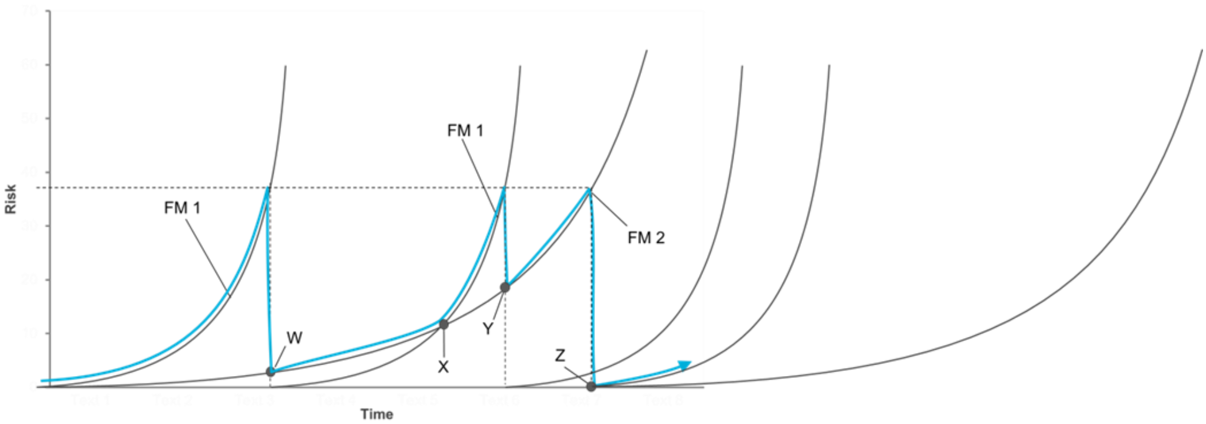


Figure 7.2

An intervention addresses one or more failure modes, either resetting or partially resetting that failure mode but leaving others unchanged.

As time progresses the asset risk increases because the probability of FM1 increases. Eventually the risk reached a specified level, and an intervention is conducted which fully addresses FM1. It does not affect FM2.

As the degradation curve for FM1 is much steeper than FM 2 it intersects with FM1's curve at point 'X' and so a transition to being FM1 driven commences again. When the risk becomes too great, another intervention is undertaken returning the risk to point 'Y' on FM2's curve. The risk then increases along FM2 until a limit is reached. At this point, because of the nature of FM2 (for example, it may be the degradation of a core component through wear) totally replacing the asset becomes necessary and this will therefore reset both failure modes to point 'Z'.

When carrying out an intervention, one must consider what failure modes are addressed whilst taking into account the cost of intervention as well as any constraints, such as outage availability for example.

7.4 Events Resulting from a Failure Mode

Each failure mode may result in one or more failure mode events. The events are categorised in a hierarchy of failure mode consequences, in terms of the impact of failure, and are comparable across the asset types. An example of a hierarchy of events, which is based on transformer failure modes, is shown in Table 4.

Event
01 - No Event
02 - Environment Noise
03 - Reduced Capability
04 - Alarm
05 - Unwanted Alarm + Trip
06 - Transformer Trip
07 - Reduced Capability + Alarm + Trip
08 - Fail to Operate + Repair
09 - Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate
10 - Overheating (will trip on overload)
11 - Cross Contamination of Oil
12 - Alarm + Damaged Component (Tap Changer) No Trip
13 - Alarm + Trip + Damaged Component (Tap Changer)
14 - Alarm + Trip + Tx Internal Damage
15 - Loss of oil into secondary containment
16 - Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)
17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement
18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire

Table 7.2

The same failure mode may result in different events. For example, Table 5 shows the potential events for the dielectric failure of a transformer bushing.

Asset Type	Item	Function	Failure Mode	Cause	Event
Transformer	Bushing	Carries a conductor through a partition such as a wall or tank and insulates it therefrom	Dielectric failure (oil, oil impregnated paper, resin imp paper, resin bonded paper, solid cast resin, SF6)	Water ingress/ treeing (partial discharge)	18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire
					17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement
					14 - Alarm + Trip + Internal Damage
					05 - Unwanted Alarm + Trip

Table 7.3

In all instances of this failure mode, the transformer will trip, and a component will be damaged, which will require investigation and repair. However, there is also a 50% chance of the transformer failing disruptively, i.e. that the transformer will need to be replaced rather than repaired. Note that these are example times and that actual return to service times may vary for individual assets depending on, for example, the nature of the failure, availability of spare parts, resourcing issues, or existing system constraints.

Event	Example Unplanned Return to Service (days)
01 - No Event	0
02 – Environment Noise	1
03 - Reduced Capability	1
04 - Alarm	1
05 - Unwanted Alarm + Trip	1
06 - Transformer Trip	1
07 - Reduced Capability + Alarm + Trip	1
08 - Fail to Operate + Repair	1
09 - Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate	1
10 - Overheating (will trip on overload)	1
11 - Cross Contamination of Oil	1
12 - Alarm + Damaged Component (Tap Changer) No Trip	5
13 - Alarm + Trip + Damaged Component (Tap Changer)	30
14 - Alarm + Trip + Tx Internal Damage	30

15 - loss of oil into secondary containment	15
16 - Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)	180
17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement	180
18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire	180

Table 7.4

7.5 Identify and Assess Failure Mode Effects

Failure Modes and Effects Analysis (FMEA) is a structured, systematic technique for failure analysis that is used to establish an asset's likelihood of failure. It involves studying components, assemblies, and subsystems to identify failure modes, their causes, and effects. NGET uses FMEA to examine the effectiveness of its current risk management approach by considering these key elements relating to potential failure modes:

1. What are the effects and consequences of the failure mode?
2. How often might the failure mode occur?
3. How effective is the current detection method?
4. How effective are the interventions for the failure mode?

FMEA views the asset as an assembly of items, each item being the part of the asset that performs a defined function. When identifying failure modes, the items under consideration are usually sub-assemblies, but there may be discrete components. Some of the asset categories are single asset types which can be separated into an integrated set of items.

It is necessary to identify the consequences of each potential failure event to determine the risk. Some illustrative guidance is provided by section 5.2.5 of BS EN 60812, which stresses the importance of considering both local and system effects – recognising that the effects of a component failure are rarely limited to the component itself.

7.6 Identify & Assess Failure Mode Effects

The determination of Probability of Failure (PoF) can be especially challenging for highly reliable assets. BS EN 60812 provides useful guidance on how to develop an estimate for PoF. Section 5.2.9 of BS EN 60812 recognises that it is very important to consider the operational profile (environmental, mechanical, and/or electrical stresses applied) of each component that contributes to its probability of occurrence. This is because, in most cases, the component failure rates and consequently failure rates of the failure modes under consideration increase proportionally with the increase of applied stresses with the power law relationship or exponentially. Probability of occurrence of the failure modes for the design can be estimated from:

5. Data from the component life testing
6. Available databases of failure rates
7. Field failure data
8. Failure data for similar items or for the component class

When probability of occurrence is estimated, the FMEA must specify the period over which the estimations are valid (such as the expected service life).

Section 5.3.4 of BS EN 60812 provides further guidance on the estimation of failure rates where measured data is not available for every asset and specific operation condition (as is generally the case for transmission assets). In this case, environmental, loading and maintenance conditions different from those relating to the "reference" failure rate data are accounted for by a modifying factor. Special care needs to be exercised to ensure that the chosen modifiers are correct and applicable for the specific system and its operating conditions.

As part of the FMEA approach, an end-of-life curve is derived for each asset. Some of these predicted deterioration curves may be theoretical as the actual mechanism may not have occurred in practice; these are based on knowledge of asset design and specific R&D into deterioration mechanisms. NGET makes use of the following sources of data in deriving deterioration curves:

1. Evidence from inspection of failed and scrapped assets
2. Results of condition assessment tests
3. Results from continuous monitoring
4. Historical and projected environmental performance (e.g. oil loss)
5. Historical and projected unreliability
6. Defect history for the asset family.

The end-of-life failure curves are expressed in terms of the data points corresponding to the ages at which 2.5%, and 97.5% of failures occur. The method for determining the end-of-life curves is explained in sections 7.8 – 7.13.

Typically, within each lead asset group there are separate end of life curves determined for each family grouping. Assignment to family groupings is through identification of similar life-limiting factors.

7.7 Factors Influencing Failure Modes Probability: Differentiators & Modifiers

There may be factors that change the shape of failure mode degradation curves depending on the asset or asset family. Examples of differentiating factors may include:

1. Some families of an asset type may have a design weakness which could influence their failure mode and hence probabilities of failure.
2. Location specific reasons, such as proximity to coastal areas or heavily polluted industrial areas, may also influence the probability of failure for the asset.

Modifiers change the rate at which an asset progresses along a curve. There may be variations in terms of the condition and duty on assets of a particular type, so while they will have the same failure modes, and hence the same degradation curves, they may proceed along the curve at a different rate.

This introduces the concept of equivalent age. An asset can be compared to another asset which was installed at the same time which might be at a different point of progression along the curve due to specific location and/or operational reasons.

By conducting inspections, it is possible to understand where each asset lies on the curve and therefore the assets can be moved down the curve, effectively reducing their equivalent age, or vice versa, as shown in Figure 5. Assets are assessed to establish any modifying factors.

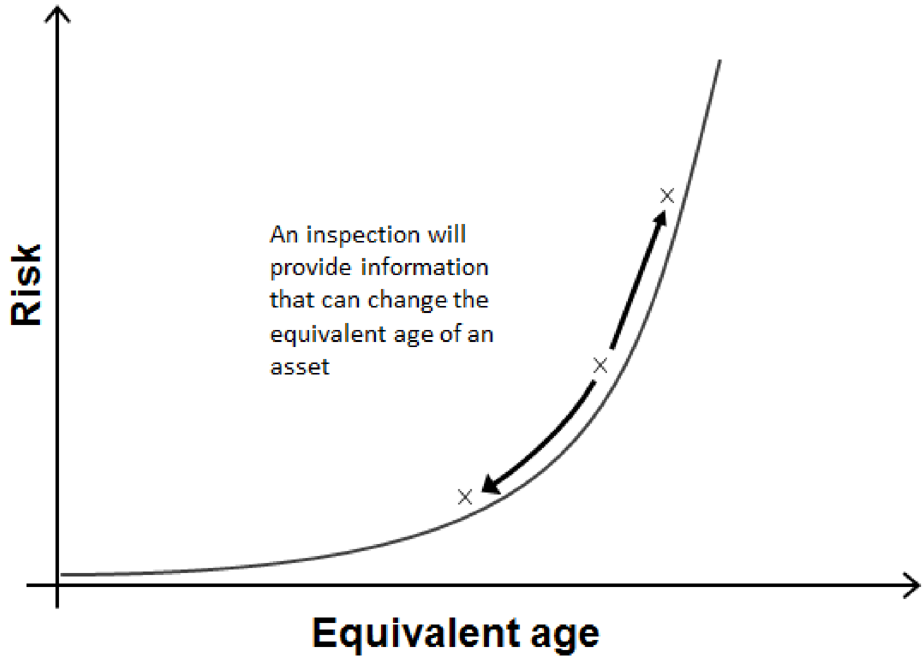


Figure 7.3

7.8 Mapping End of Life Modifier to Probability of Failure

The end-of-life probability of failure (PoF), which is the probability of end-of-life failure in the next year given that the asset is still surviving at the beginning of the year, is determined from the end of life (EoL) modifier. The EoL modifier is determined from the asset's current condition, duty, age, and asset family information and, through the process described below. This is converted to PoF.

A probability mapping function is required to enable mapping from an EoL modifier to a PoF. Figure 6 below illustrates distributions representing the end-of-life failure mode for a population of transformers.

PoF cannot be utilised at an individual asset level to infer individual asset risk, and therefore the PoF values need to be aggregated across the asset population to support the calculation of risk. Over a population of assets at a given PoF we have an expectation of how this PoF will continue to deteriorate over time, duty, or condition. This is shown by the PoF curve in red in Figure 6.

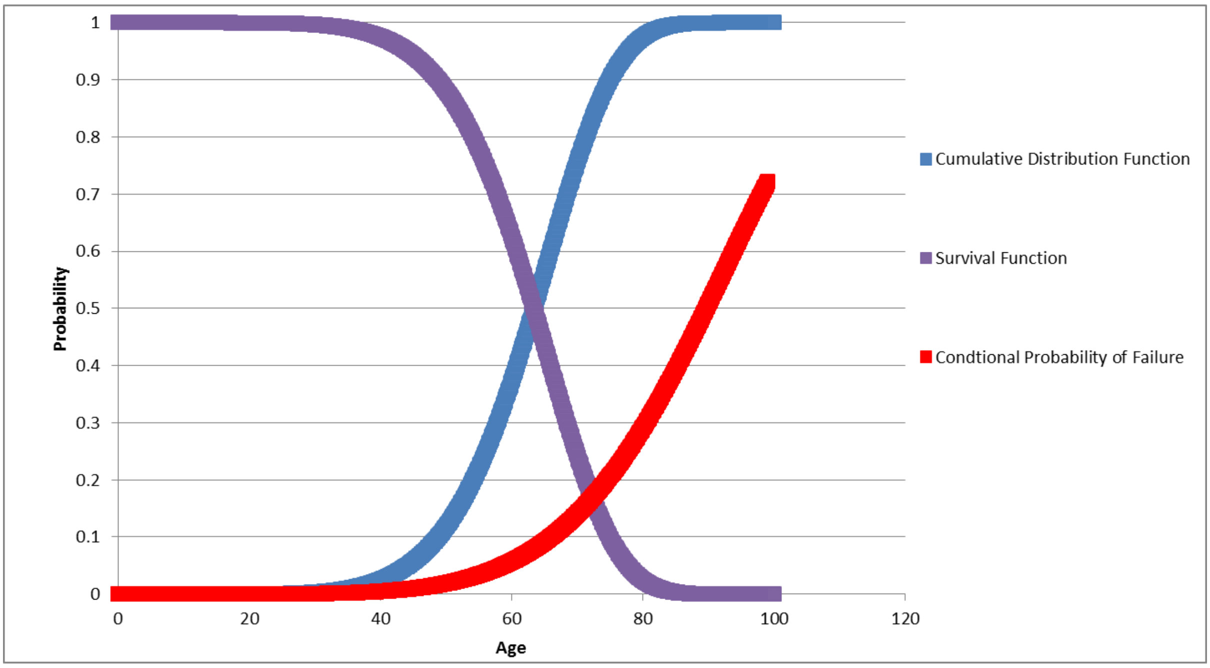


Figure 7.4

The development of a methodology that maps the EoL modifier to PoF considers the actual number of failures experienced, it should then be validated against the expected population survival curve, and it should satisfy the following requirements:

1. High scoring young assets should be replaced before low scoring old assets. The mapping function achieves this objective because high scoring assets will always reach their AAL quicker than those of low scoring assets.
2. When two assets of similar criticality have the same PoF then the older asset should be replaced first. The mapping function will assign the same PoF to both assets, so they reach their respective AAL at the same time. In practice the planner could prioritise the older asset for replacement over the younger asset without penalty.
3. When an asset is not replaced the PoF should increase. The EoL modifier score reflects the condition of the asset and will therefore increase over time. This means the PoF will also increase.
4. A comprehensive and steady replacement programme will lead to a stabilisation of the population's average PoF. The proposed methodology will satisfy this requirement as worsening PoF would be offset by replacements.
5. The PoF and resulting risks must be useful for replacement planning. The proposed methodology is validated against the expected survival function, so should be compatible with existing replacement planning strategies.
6. Outputs should match observed population data. The expected survival function for the population is already identified based on known asset deterioration profiles and NGET experience. The mapping to PoF method is validated against this expected population statistic.

The mapping function is given by the following equations.

$$Conditional\ PoF = \exp\left(k * EoLmod^{\alpha}\right) - 1$$

Equation 2

$$k = ln\frac{(1+\beta)}{{EoLmod_{AALH}}^{\alpha}}$$

Equation 3

Where:
EoLmod = End of Life Modifier
$EoLmod_{AALH}$ = End of Life modifier at Anticipated Age of Low Health

The parameters α and β are tuned so that the deterioration profile over the population is consistent with the expected survival function for the relevant population of assets. The expected survival function is given by the FMEA earliest and latest onset of failure values, which have been determined though the transmission owner experience using all available information such as manufacturer data and understanding of asset design.

The parameter k scaling value ensures that for an EoL modifier score of $EoLmod_{AALH}$ (default value of 100) the expected PoF is obtained (given as β in the formula below).

In the following example, the PoF mapping function is derived for a transformer, then the mapping curve parameters are systematically adjusted through a process of validation and calibration against the expected population's survival curve.

The PoF mapping function is shown in the figure below for a transformer with α=1.7 and β=10%.

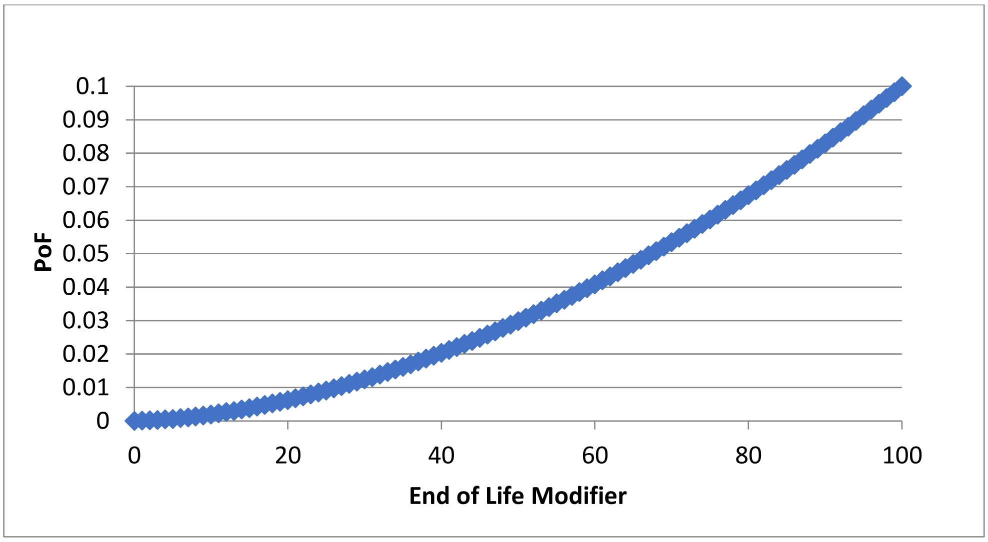


Figure 7.5

A minimum PoF of 0.0001 will be applied to assets that have an actual age greater than half of their earliest onset of failure (this is named the PoF Floor).

7.9 Determining Alpha (α), Beta (β) and Validation

To tune the parameters, alpha (α) and beta (β), and validate the approach, the Predicted Actual Age at Failure (PAAF) for each asset needs to be determined so that a population survival curve may be determined. Using the PoF, an Equivalent Age (EA) is identified using the red curve in Figure 6 above. The PAAF calculation also needs actual Age and the age when the asset has reached a state of very poor health (Anticipated Age of Low Health, AALH).

$$PAAF = \text{Age} + (\text{AALH} - \text{EA})$$

Equation 7.2

The EoL modifier score for an individual asset puts it on a PoF curve n years away from the AALH. This n years value can be interpreted as the difference between the AALH and the equivalent age of the asset (AALH – EA). Combining with actual age gives the PAAF, as shown in Equation 9.

The PAAF can then be used to generate a survival curve that indicates the percentage of the population that is still surviving at a given age. Comparison with the expected survival curve allows the parameters alpha (α) and beta (β) to be calibrated. Figure 8 below shows an example modelled transformer survival curve based on PAAF (blue) overlaid with the expected survival curve generated from the FMEA curve (red). The modelled PoF is observed to give a good fit to the expected survival curve up to 60 years old. The trend diverges from the expected survival curve. This section of the survival curve is not as well understood, as there is little operational experience at this older age range. The linear appearance of the older section of the modelled survival curve (blue) is driven by a large population of transformers that are all around a similar age of 49 years old and have a relatively even spread of EoL modifier scores.

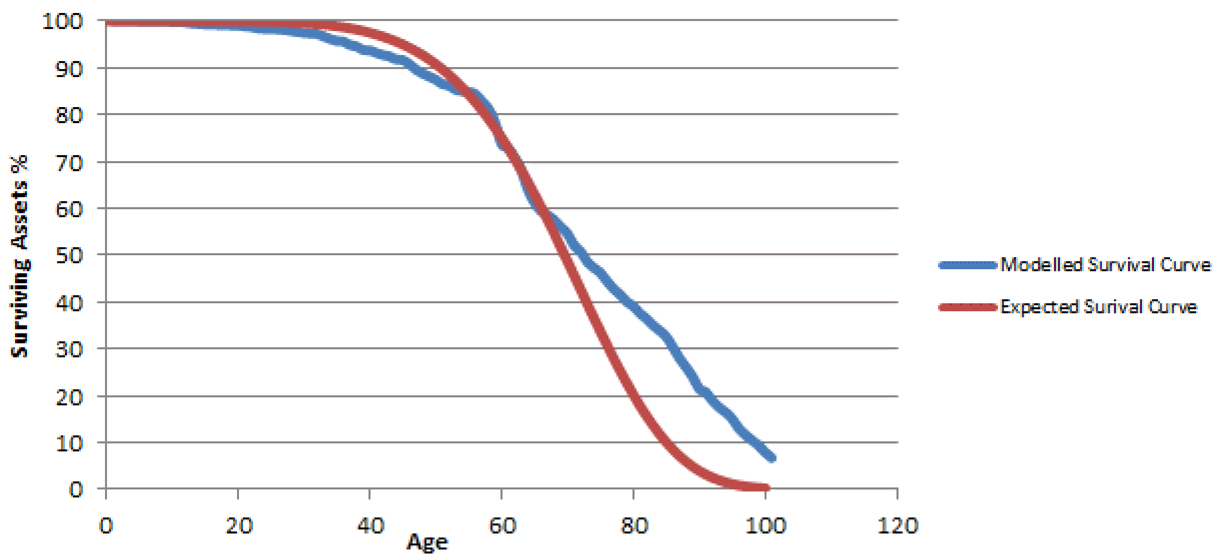


Figure 7.5

Beta (β) sets the maximum PoF which would be expected for an asset that has reached a state requiring replacement. For the purpose of implementing this methodology, β is given an assumed value of 10% (meaning 10% probability of failing in the next year) for an EoL modifier score of $\text{Score}_{\text{AALH}}$, which represents an asset in a state requiring replacement. These parameters will be flexed where this is necessary to achieve alignment with the expected number of events and expected deterioration. The $\text{Score}_{\text{AALH}}$ parameter will be set at a score representative of an asset in a state requiring replacement, which is usually a score of 100.

The total PoF across the population is obtained by summing the individual PoFs; this is then compared to the observed replacements noting that many assets are expected to be replaced before they fail. The value for β may be tuned such that the number of replacements is similar to what is observed, but any tuning needs to be performed in conjunction with the parameter α. These parameters primarily need to be calibrated to achieve good agreement between the PAAF survival curve with the policy survival curve, as described in the previous section, but the total PoF should also be inside an acceptable range of expected values.

The parameters alpha (α) and beta (β) are both calibrated by considering population level statistics. In the same sense the PoF or risk is only meaningful when aggregated across the asset/EoL FM population.

7.10 Oil Circuit Breaker PoF mapping example

The analysis described above was repeated for Oil Circuit Breaker (OCB) EoL modifier scoring data to validate and quantify the proposed method against expectation based on NGET experience. The EoL modifier values are mapped to a PoF using a similar function to that shown in Figure 8 above, noting that the value of α and β will be specific to this OCB asset type. For the purpose of implementing this methodology a PoF value of β=10% per year is assumed for an EoL modifier score of 100. An initial value of α is selected and it is assumed that it will be adjusted to provide the best fit.

Using the same method described above for transformers the PAAF for each OCB on the network is determined. Plotting these PAAF values as a survival curve, overlaid with the expected survival curve, allows quantification of the model against expected asset deterioration, and provides a mechanism for tuning the mapping parameter α. The modelled survival curve shown in Figure 9 below has been produced with α=2.1 and β=10%.

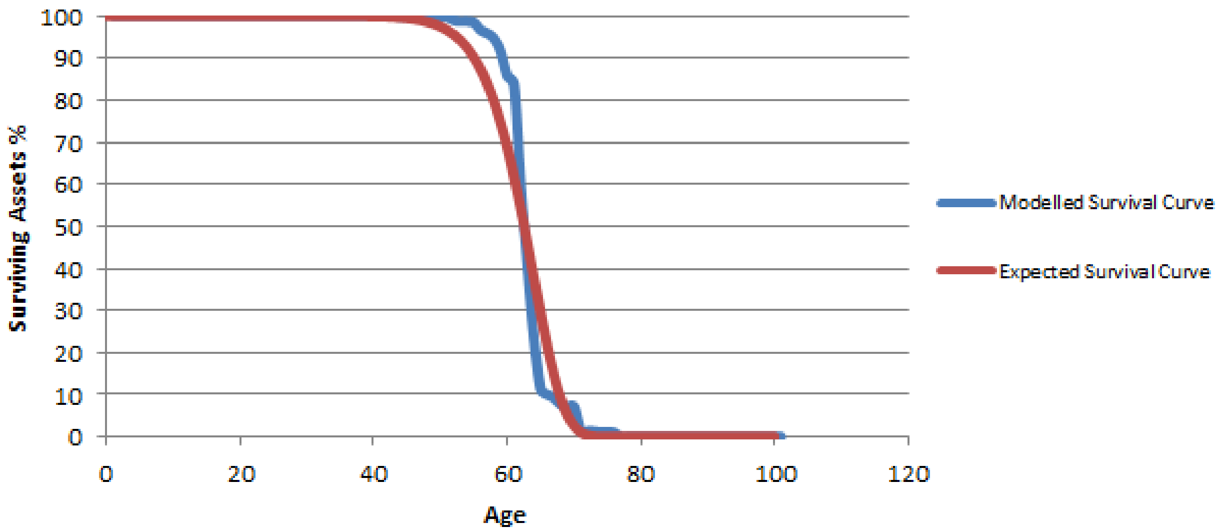


Figure 7.6

7.11 Calculating Probability of Failure

As described above the PoF curve is based on two data points that correspond to the ages at which specific proportions of the asset's population is expected to have failed. Using these data points we can construct a cumulative distribution function F(t). The survival function, or the cumulative probability of survival until time t, is given as: S(t) = 1-F(t). The probability of failure, which is the probability an asset fails in the next time period given that it is not in a failed state at the beginning of the time period, is then given by the following formula, where it is equivalent age in the case of end-of-life failure modes:

$$PoF(t) = S(t) - S(t+1)$$

Equation 7.3

In order to calculate the end-of-life PoF associated with a given asset, the asset will need to be assigned an EoL modifier. This EoL modifier is derived from values such as age, duty, and condition information where it is available. In the absence of any condition information, age is used. The service experience of assets of the same design and detailed examination of decommissioned assets may also be considered when assigning an EoL modifier. Using the EoL modifier an asset's equivalent age can then be determined and mapped onto a specific point on the PoF curve.

The generalised EoL modifier (*EoLmod*) formula has the following structure for assets that have underlying issues that can be summed together:

$$EoLmod = \sum_{i=1}^{n} C_i$$

Equation 7.4

Where
n = number of components

Or, for transformer assets that are single assets with parallel and independent failure modes, the following generalised EoL modifier formula is used:

$$EoLmod = \left(1 - \prod_{i=1}^{n} \left(1 - \frac{C_i}{C_{max}}\right)\right) * 100$$

Equation 7.5

C_i = an individual component parameter of the end-of-life modifier
C_{max} = the maximum score that the component can be assigned

For some of the lead asset types, the generalised formula will need to be nested to derive an overall asset EoL modifier. For example, in the case of overhead lines (OHLs), the maximum of the preliminary EoL modifier and a secondary EoL modifier are taken.

The EoL modifier will range from 0 to 100, where 100 represents the worst health that an asset could be assigned. It is then necessary to convert the EoL modifier to a PoF to enable meaningful comparison across asset types.

As far as reasonably possible the scores assigned to components of the EoL modifier are set such that they are comparable e.g. are the same magnitude. This enables the EoL modifier between different assets in the same family to be treated as equivalent. The validation and testing of these scores are described in the testing section of the NARM Common Methodology; and a summary of these activities is given in Appendix B.

7.12 Forecasting Probability of Failure

Future PoF is estimated by following the appropriate failure curve. Depending on the type of failure mode the current position on the failure curve is identified using either age, equivalent age, or last intervention date. The forecast is determined by following along this curve, usually at the rate of one year per year. Figure 10 illustrates the PoF for an asset highlighting the PoF at an equivalent age of 80.

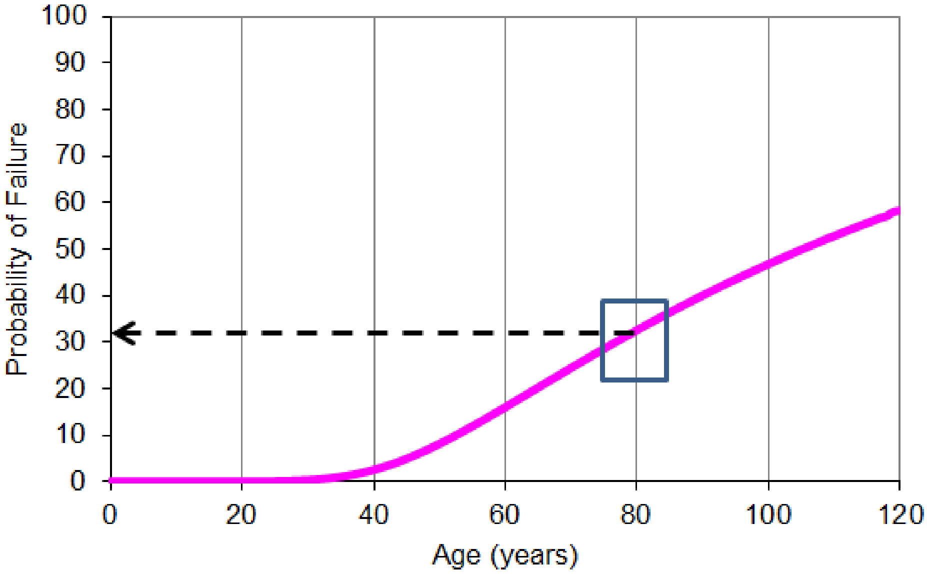


Figure 7.7

The forecast probability of failure in future years can then be obtained by following along the curve. For example, the forecast for Y+7 would be the value given by the above curve at the equivalent age of 87. Note that in this case it is not the real age of the asset, but an equivalent age that has been determined through the process described in the above sections.

Where appropriate and enough historical data exists, a rate multiplier can be applied, so that for each annual time step in forecast time equivalent age is increased or decreased by the rate multiplier time step. The default value of the rate multiplier time step is set as 1.0 per year. This modelling feature will allow high duty assets to be forecast more accurately.

7.13 Summary of the Process for Determining EoL Probability of Failure

The process illustrated below will be used to determine the PoF of each asset. This is done by translating through a probability mapping step, so that the appropriate end of life curve may be used to determine the probability of an asset having failed.

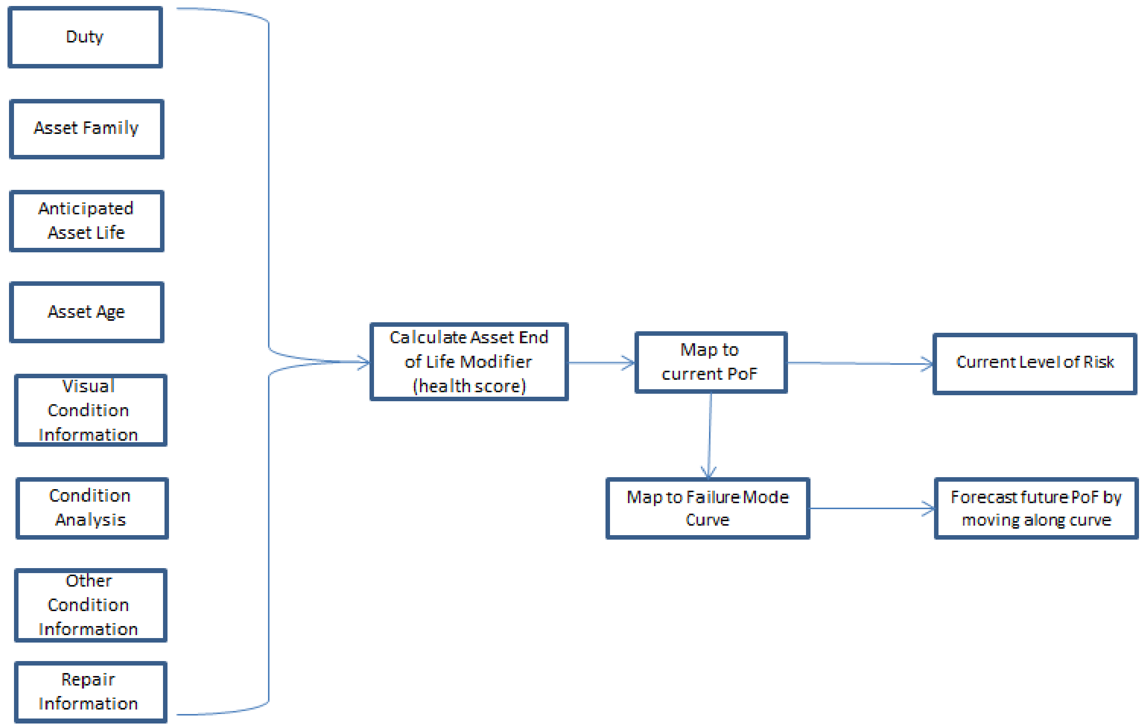


Figure 7.8

8 Consequences of Failure

The Consequences of Failure are evaluated in four major categories: system, safety, environmental and financial. The output is best considered a method of comparing the relative risk of different items, i. e an index.

Consequence	Description
System	The impact on the network of the failure and any subsequent intervention required
Safety	Impact of direct harm to public/personnel as a result of failure mode
Environment	Impact of failure mode taking into account the sensitivity of the geographical area local to the asset
Financial	Cost of the intervention needed to address and resolve the failure

Table 8.1

These categories reflect the impact of the various failure modes which are specific to the asset and the consequences are consistent for each class of failure mode. The impact of the various failure modes will vary depending on the type of failure. For example, for less disruptive failure modes there may be no impact from a safety perspective.

Safety and environmental consequences are specific to the asset and its physical location. We introduce the concept of exposure to quantify differences arising from this.

In a highly meshed system, such as a transmission network, consideration of system effects is important. The current methodology employs a comprehensive system of consequence evaluation.

Each consequence will be monetised and the price base for consequence of failure is defined in Section 5.

NGET states which failure modes have been included in the analysis and explains why the chosen failure modes are considered appropriate for the analysis.

8.1 System Consequences

The System Consequences model considers the degree of redundancy associated with a given asset. A substation benefitting from a higher degree of redundancy will be considered to have lower system risks.
System consequences comprises of the following elements :
Boundary Transfer costs, which are the increase in cost to run the network with a restricted capacity.
Reactive compensation, which is the cost of replacing reactive compensation after a fault.
Customer disconnections, which reflect the generation disconnected and replaced, the Value Of Lost Load, and impacts on vital infrastructure.

The system consequence of a failure or failure mode effect of an asset is an indication of the asset's importance in terms of its function to the transmission system as given by the disruption to that function caused by the failure. It is measured in terms of certain system related costs associated with system consequences incurred by the industry electricity sector if that asset were to experience a failure. These system costs incurred due to an asset failure can be divided into two categories, customer costs and Electricity System Operator (ESO) costs. Regardless of who initially pays these costs they are ultimately borne by electricity consumers. Customer costs are incurred as a result of the disconnection of customers supplied directly or indirectly (via a distribution network) by the transmission system. The cost for demand disconnections is expressed as the economic value that the user assigns to that lost load. In the case of generators being disconnected from the network there is a mechanism of direct compensation payments from the ESO. The second category of costs are those that the ESO incurs in undertaking corrective and preventative measures to secure the system after asset failures have occurred. These include generator constraint payments, response and reserve costs and auxiliary services costs.

Unlike the environmental, financial and safety consequences of asset failures, the existence and scale of network risk due to asset failures is dependent on the functional role that the failed asset plays in the transmission system. The transmission system is designed with a degree of resilience that seeks to ensure the impact of asset faults is contained within acceptable limits. It is the NETS SQSS that mandates a certain level of resilience that the design and operation of the transmission system must meet when faced with a range of scenarios and events. It is a license obligation of TOs that their networks comply with the NETS SQSS.

A range of negative system consequences (unacceptable overloading of primary transmission equipment, unacceptable voltage conditions or system instability) must be avoided for 'defined secured events' under certain network conditions. The required resilience is not absolute nor is it uniform across the network. The philosophy behind the NETS SQSS is that lower severity consequences are to be accepted for relatively high probability (and therefore high frequency) faults while more severe consequences are only to be accepted for lower probability events. Figure represents this philosophy.

This approach is further influenced by other considerations such as the geographical location of the assets in question i.e. which TO License Area they are in, and for what timescales the network is being assessed (near term operational timescales vs. long term planning timescales). The level of resilience required also varies depending on the function of the part of the network in question. Parts of the network which connect demand, generation or make up part of the Main Interconnected Transmission System (MITS) all have distinct design requirements dependent upon their importance to the Transmission System and the total economic value of all the customers they supply.

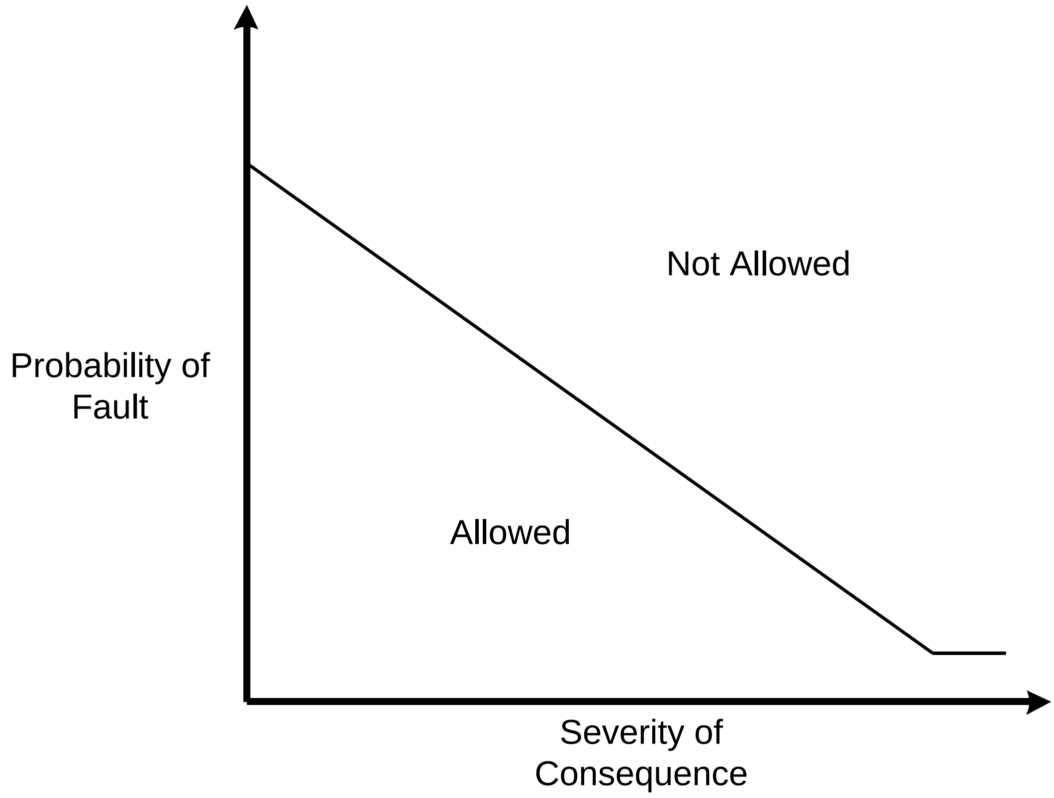


Figure 8.1

Events that the NETS SQSS requires a degree of resilience against are described as 'secured events'. These are events that occur with sufficient frequency that it is economic to invest in transmission infrastructure to prevent certain consequences when such events occur on the system. Secured events include faults on equipment and these events range from single transmission circuit faults (highest frequency) to circuit breaker faults (lowest frequency). When an asset fault occurs that results in the loss of only a single transmission circuit in an otherwise intact network, almost no customer losses are permitted, and all system parameters must stay within limits without the ESO taking immediate post-fault actions. While in the case of circuit breaker faults the NETS SQSS only requires that the system is planned such that customer losses are contained to the level necessary to ensure the system frequency stays within statutory limits to avoid total system collapse.

The key assumption that underpins this variation in permitted consequences of faults is that most faults are weather related and that faults caused by the condition of the asset are rare. This can be seen in that faults on overhead lines (often affected by wind and lightning) are relatively frequent events (≈20% probability per 100 km 400 kV circuit per annum) while switchgear faults are relatively less frequent (≈2% probability per 2-ended 400 kV circuit per annum). Another key assumption in the design of the SQSS is that faults are relatively short. A vast majority of circuits have a post-fault rating that is time limited to 24 hours, it is expected that faults will be resolved within this time so that this rating will not be exceeded.

Asset failures driven by asset condition do not conform to these key assumptions, they occur in assets regardless of their exposure to the elements and they can significantly exceed 24 hours in duration. The system therefore cannot be assumed to be designed to be resilient against even a single asset failure. Even if system resilience is sufficient to avoid an immediate customer or operator cost, no asset fault or failure that requires offline intervention can be said to be free from a risk cost. At the very least, the unavailability of the asset reduces system resilience to further events and therefore increases exposure to future costs.

8.1.1 Quantifying the System Risk Due to Asset Faults & Failures

Fundamentally, the transmission system performs three functions. It receives power from generators, transports power where it is needed and delivers it to consumers. The system risk cost of a fault or failure can be quantified by combining the following costs:

1. The economic value assigned to load not supplied to consumers including directly connected demand customers. Commonly described as Value of Lost Load (VOLL) in units of £/MWh
2. The cost of compensating generators disconnected from the transmission system, based on the market cost of generation (£/MWh), the size of the generator (MW) and the expected duration of disconnection (hours)
3. The cost of paying for other generators to replace the power lost from disconnected generation based on the market cost of replacement generation (£/MWh) and number of megawatt hours that require replacement.
4. The increased cost in transporting power across the wider transmission network. This is comprised of:
    a. Constraint payments to generators due to insufficient capacity in part of the transmission system. This comprises the costs to constrain off generation affected by the insufficient capacity and the cost to constrain on generation to replace it. If there is insufficient replacement generation capacity, costs will include demand reduction.
    b. Payments to generators to provide auxiliary services which ensure system security and quality of supply e.g. the provision of reactive power.

The applicability and size of these cost sources are dependent upon the role of the failed asset in the system. Some assets are solely for the connection of generation or demand, while others will provide multiple functions.

The methodology for calculating these potential costs is split into three parts:

1. A customer disconnection methodology, incorporating the cost of disconnecting generation, total consumer demand and vital infrastructure sites (1, 2 and 3 above)
2. A boundary transfer methodology that estimates potential generator constraint payments (4a)
3. A reactive compensation methodology that estimates the cost of procuring reactive power to replace that provided by faulted assets (4b)

Each of these methodologies will be described in turn in the following sections. All three elements share a common structure that can be expressed by Equation 8.1.

$$Cost\ of\ System\ Impact\ = probability\ x\ duration\ x\ size\ x\ cost\ per\ unit$$

Equation 8.1

The total cost of system impact of a failure mode of an asset will be the sum of the consequence costs that come from the three above costs.

8.1.2 Customer Disconnection – Customer Sites at Risk

With the exception of radial spurs, assets on the system will usually contribute towards the security of more than one substation that connects customers to the network. However, the fewer other circuits that supply a substation, the more important that asset is for the security of the site. In order to identify which sites are most at risk of disconnection because of the failure of a specific asset, the number of circuits left supplying a customer connection site after a failure of an asset, *X*, is defined;

$$X = number\ of\ parallel\ circuits\ supplying\ customer\ site(s) - number\ of\ circuits\ tripped\ as\ a\ result\ of\ the\ Failure\ Mode\ Effect\ of\ the\ asset$$

Equation 8.2

Circuit availability statistics indicate that the importance of a circuit decreases by around two orders of magnitude for each extra parallel circuit available. Given that the uncertainty of other inputs into these calculations will be greater than 1% it is a reasonable simplification to neglect all customer sites with values of *X* greater than the minimum value of *X*; $X_{min}=min(X)$.

Once there are four or more circuits in parallel supplying a site additional circuits do not necessarily decrease the probability of losing customers as the capacity of the remaining circuits will not be sufficient to meet the import/export of the customers at risk. In parts of the network where the number and rating of circuits connecting a substation are determined solely by the need to meet local demand, there is a significant risk that once two or three circuits have been lost cascade tripping of remaining circuits due to overloading will result.

Therefore:

- For assets on circuits containing transformers down to 132 kV or below if $X_{min} > 3$ it will be treated as $X_{min} = 3$ for the purposes of calculating the Probability of Disconnection (P_{oc}) and Duration (*D*).
- Otherwise for assets on circuits at 275 kV or below if $X_{min} = 4$ it will be treated as $X_{min} = 3$ for the purposes of calculating the Probability of Disconnection (P_{oc}) and Duration (*D*).
- Otherwise if $X_{min} > 3$ then the risk of customer disconnection will be neglected as negligible.

As there will often be multiple customer connection sites with $X=X_{min}$, to ensure that the methodology is efficient and operable a variable *Z*, is introduced which is equal to the number of customer sites with $X=X_{min}$ for a given asset. Only the largest group of customer sites that would be disconnected by the loss of a further X_{min} circuits is considered explicitly while the extra risk of customer disconnection due to other combinations of circuit losses is approximated by the use of the risk multiplier coefficient M_Z:

$$M_Z = \frac{\sum Z + (Z-1) + (Z-2) + \dots}{Z}$$

Equation 8.3

Intuitively $M_1 = 1$, and M_Z scales with increasing values of *Z*. Figure 13 illustrates an example of how M_Z is calculated with three customer sites (M_3):

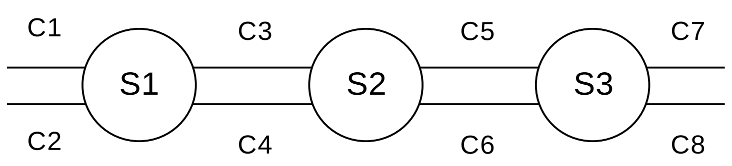


Figure 8.2

Three substations labelled S1, S2 and S3 are part of a double circuit ring with eight circuits labelled C1-C8. Each substation is immediately connected to the rest of the system by four circuits and could be disconnected from the system if these four immediate circuits were lost. However, each substation could also be disconnected by other combinations of four circuit losses also. For example S2 could be disconnected by the loss of C3, C4, C5 and C6, but also by losing C3, C4, C7 and C8 or C1, C2, C5 and C6 etc. More than one substation would be lost for these other combinations and all three substations would be lost for a loss of C1, C2, C7 and C8.

In order to calculate the total system consequence of a failure mode of an asset that is part of C1 it is assumed that the volume and cost per unit of customer connections are approximately evenly distributed among the substations (L for each substation) and that the probability (P) and duration (D) of each four circuit combination being lost is approximately equal. The relative consequence of a loss event is then determined only by the number of customers lost. So, a loss of S1 and S2 is twice the consequence of losing only S1. There is one combination of four circuit losses involving C1 that disconnected a single substation, one combination that disconnects two substations and one that disconnects all three. Therefore, the risk cost is:

$$Risk\ cost = (1 \times PDL) + (1 \times 2PDL) + (1\ \times 3PDL) = 6\ PDL$$

Equation 8.4

Given the risk cost of losing all three sites at once is 3PDL so the risk cost can be expressed as a function of the risk cost of losing all three sites at once:

$$Risk\ cost = 6\ PDL = 2 \times 3PDL = 3PDLM_3$$

Equation 8.5

Therefore, M_3 is equal to 2.

8.1.3 Customer Disconnection – Probability

The probability of a generator or consumer being disconnected as a consequence of an asset failure is a function of a wide range of variables including the physical outcome of the failure, the local network topology, asset composition of circuits, asset loading, physical proximity of assets, protection configuration and operation options for restoration. The probability of consequence is calculated as a function of five probabilities, shown in Table .2

Probability	Symbol	Value	Determination of Value
Coincident outage	P_o	$0.056*X_{min}$	TO statistics on planned unavailability of circuits
Damage to another circuit	P_d	Varies by asset class and failure mode. Typical range of 0 to 0.014.	TO historical experience of explosive/incendiary failures of failure mode
Maloperation of another circuit	P_m	0.01	TO statistics on protection maloperation
Coincident fault to another circuit	P_f	$0.014*X_{min}$	TO fault statistics
Overloading of remaining circuit	P_l	If MWD>1200 then 0.09 Otherwise, Zero.	TO specific network design

Table 8.1

The probabilities P_o, P_d, P_m, P_f and P_l are determined separately by each TO according to their own historical experience and network properties.

The probabilities in Table can be combined to create a probability tree for each value of X_{min} between 0 and 3. Below are the resulting equations for P_{oc}, the probability of disconnection.

$$\text{For } X_{min} = 0,\ P_{oc} = 1$$

Equation 8.6

$$\text{For } X_{min} = 1,\ P_{oc} = P_d + N_dP_o + N_oN_dP_m + N_oN_dN_mP_f$$

Equation 8.7

$$\text{For } X_{min} = 2,\ P_{oc} = P_d^2 + 2P_dN_dP_o + 2P_dN_dN_oP_m + 2P_dN_dN_oN_mP_f + N_d^2P_oP_m + N_d^2P_oN_mP_f + N_d^2N_oP_mP_f + N_d^2N_oN_mP_f^2$$

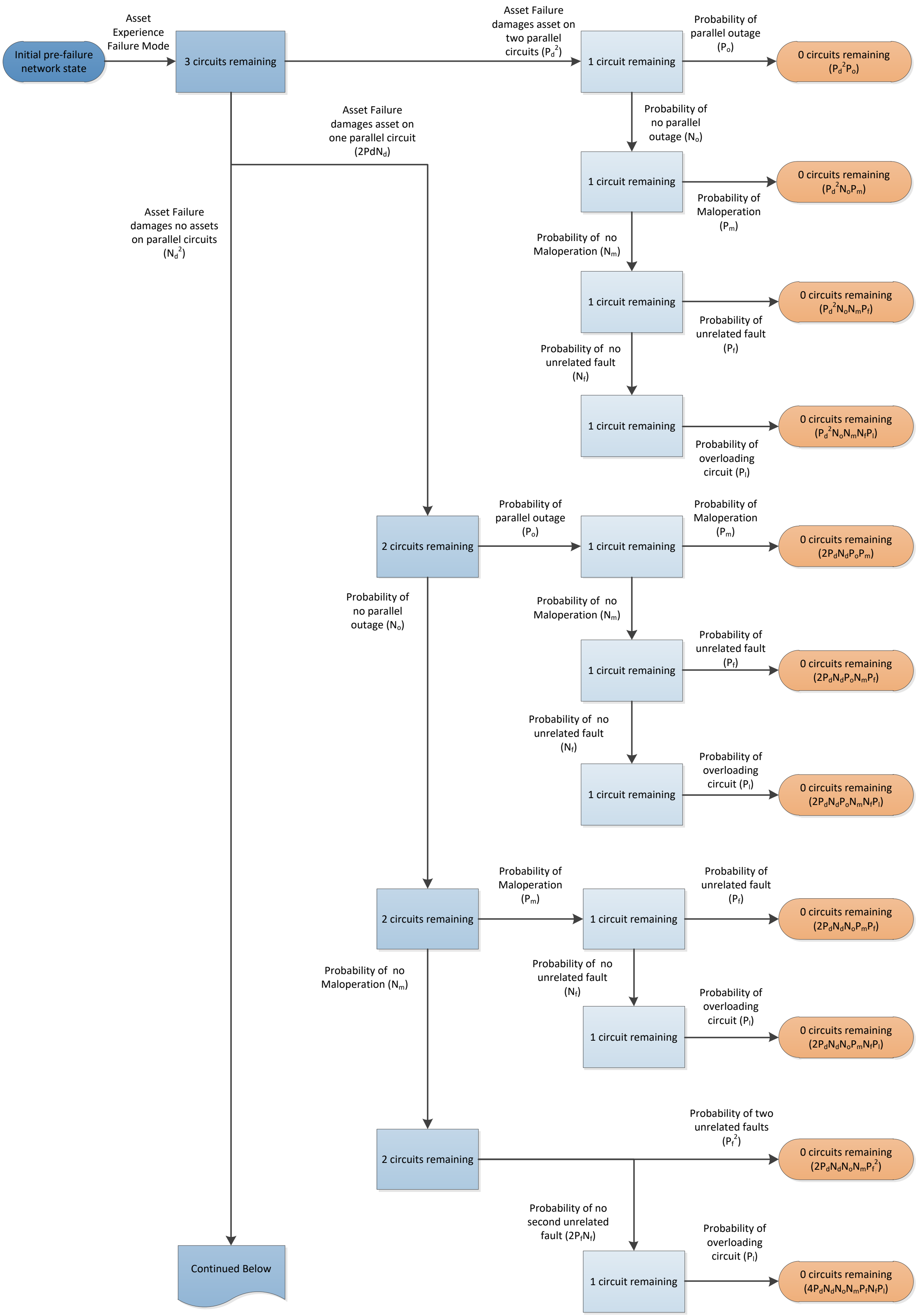
Equation 8.8

$$\text{For } X_{min} = 3,\ P_{oc} = P_d^2P_o + P_d^2N_oP_m + P_d^2N_oN_mP_f + P_d^2N_oN_mN_fP_l + 2P_dN_dP_oP_m + 2P_dN_dP_oN_mP_f + 2P_dN_dP_oN_mN_fP_l + 2P_dN_dN_oP_mP_f + 2P_dN_dN_oP_mN_fP_l + 2P_dN_dN_oN_mP_f^2 + 4P_dN_dN_oN_mP_fN_fP_l + N_d^2P_oP_mP_f + N_d^2P_oP_mN_fP_l + N_d^2P_oN_mP_f^2 + 2N_d^2P_oN_mP_fN_fP_l + N_d^2N_oP_mP_f^2 + 2N_d^2N_oP_mP_fN_fP_l + N_d^2N_oN_mP_f^3 + 3N_d^2N_oN_mP_f^2N_fP_l$$

Equation 8.9

Where N_o, N_d, N_m, N_f and N_l are the probabilities of no outage, no damage, no maloperation, no coincident faults and no overloading respectively.

While these equations appear complex, for Xmin of 3 or greater, system risks as-evaluated tend to zero. Probability tree diagram for the most complex of the four cases, $X_{min} = 3$ follow for the purposes of understanding.



Initial pre-failure network state
Asset Experience Failure Mode
3 circuits remaining
Asset Failure damages asset on two parallel circuits (P_d^2)
1 circuit remaining
Probability of parallel outage (P_o)
0 circuits remaining ($P_d^2P_o$)
Probability of no parallel outage (N_o)
1 circuit remaining
0 circuits remaining ($P_d^2N_oP_m$)
Probability of Maloperation (P_m)
Probability of no Maloperation (N_m)
1 circuit remaining
0 circuits remaining ($P_d^2N_oN_mP_f$)
Probability of unrelated fault (P_f)
Probability of no unrelated fault (N_f)
1 circuit remaining
0 circuits remaining ($P_d^2N_oN_mN_fP_l$)
Probability of overloading circuit (P_l)
Asset Failure damages asset on one parallel circuit ($2PdN_d$)
Asset Failure damages no assets on parallel circuits (N_d^2)
2 circuits remaining
Probability of parallel outage (P_o)
1 circuit remaining
Probability of Maloperation (P_m)
0 circuits remaining ($2P_dN_dP_oP_m$)
Probability of no parallel outage (N_o)
Probability of no Maloperation (N_m)
1 circuit remaining
Probability of unrelated fault (P_f)
0 circuits remaining ($2P_dN_dP_oN_mP_f$)
Probability of no unrelated fault (N_f)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($2P_dN_dP_oN_mN_fP_l$)
2 circuits remaining
Probability of Maloperation (P_m)
1 circuit remaining
Probability of unrelated fault (P_f)
0 circuits remaining ($2P_dN_dN_oP_mP_f$)
Probability of no Maloperation (N_m)
Probability of no unrelated fault (N_f)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($2P_dN_dN_oP_mN_fP_l$)
2 circuits remaining
Probability of two unrelated faults (P_f^2)
0 circuits remaining ($2P_dN_dN_oN_mP_f^2$)
Probability of no second unrelated fault ($2P_fN_f$)
Probability of overloading circuit (P_l)
1 circuit remaining
0 circuits remaining ($4P_dN_dN_oN_mP_fN_fP_l$)
Continued Below

Figure 8.3

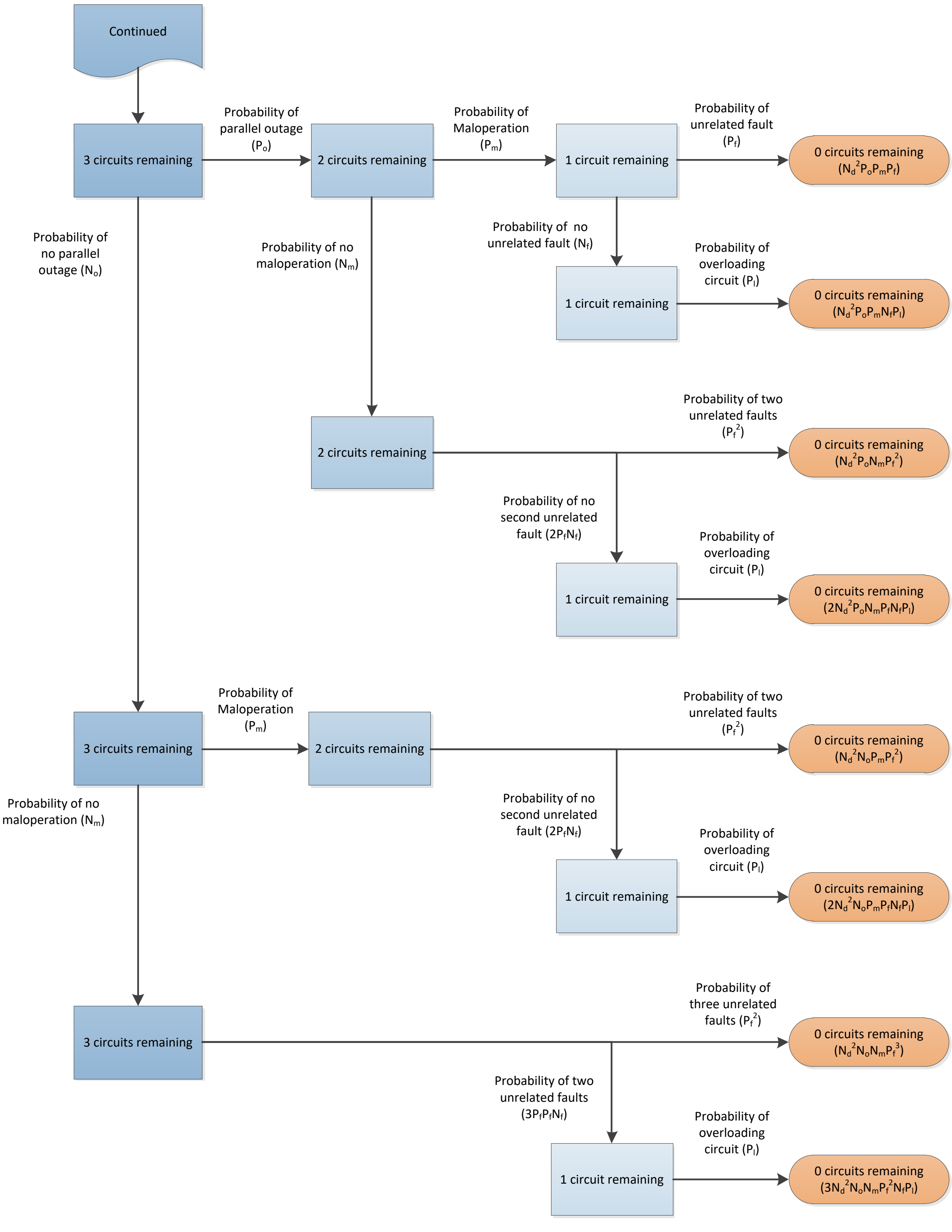

Continued
3 circuits remaining
Probability of parallel outage (P_o)
2 circuits remaining
Probability of Maloperation (P_m)
1 circuit remaining
Probability of unrelated fault (P_f)
0 circuits remaining ($N_d^2P_oP_mP_f$)
Probability of no parallel outage (N_o)
Probability of no maloperation (N_m)
Probability of no unrelated fault (N_f)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($N_d^2P_oP_mN_fP_l$)
2 circuits remaining
Probability of two unrelated faults (P_f^2)
0 circuits remaining ($N_d^2P_oN_mP_f^2$)
Probability of no second unrelated fault ($2P_fN_f$)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($2N_d^2P_oN_mP_fN_fP_l$)
3 circuits remaining
Probability of Maloperation (P_m)
2 circuits remaining
Probability of two unrelated faults (P_f^2)
0 circuits remaining ($N_d^2N_oP_mP_f^2$)
Probability of no maloperation (N_m)
Probability of no second unrelated fault ($2P_fN_f$)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($2N_d^2N_oP_mP_fN_fP_l$)
3 circuits remaining
Probability of three unrelated faults (P_f^2)
0 circuits remaining ($N_d^2N_oN_mP_f^3$)
Probability of two unrelated faults ($3P_fP_fN_f$)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($3N_d^2N_oN_mP_f^2N_fP_l$)

Figure 8.4

8.1.4 Customer Disconnection – Duration

A similar approach is taken with the expected duration of such a disconnection event. This is dictated by the failure mode of the asset in question, and both operational and asset interventions available to restore supply to the customers. In order to calculate the duration of disconnection, six separate durations are introduced in Table .

Duration	Symbol	Value (h)	Determination of Value
Duration of failure mode unavailability	D_{fm}	Varies by failure mode effect and asset type with a range of 0 to 4,320	TO experience of failure durations
Outage restoration time	D_o	0.5	TO statistics on planned unavailability of circuits
Circuit damage restoration time	D_d	0.5	TO historical experience of explosive/incendiary failures of failure mode
Protection mal-operation restoration time	D_m	0.173	TO statistics on protection maloperation
Unrelated fault restoration time	D_f	0.5	TO fault statistics
Circuit overload restoration time	D_l	0.165	TO historical experience of overload trips

Table 8.2

The durations D_{fm}, D_o, D_d, D_m and D_f are determined separately by each TO according to their own methodology outlined in TO specific appendices. The duration of customer loss is calculated by weighting the probabilities of the event combinations outlined in the formulae for P_{oc} and multiplying by the shortest of the above durations that apply to that event combination. For example, if a failure mode with X_{min} = 2 and disconnection is due to a combination of the failure mode, a parallel outage and protection mal-operation then the minimum of D_{fm}, D_o and D_m is weighted with the other minimum durations of other disconnection combinations. Below are the equations for D for different values of X_{min}.

$$\text{For } X_{min} = 0,\ D = D_{fm}$$

Equation 8.10

$$\text{For } X_{min} = 1,\ D=[min(Dfm, Dd)Pd + min(Df, Do)NdPo + min(Dfm, Dm)NoNdPm + min(Dfm,Df)NoNdNmPf / Poc$$

Equation 8.11

$$\text{For } X_{min} = 2,\ D = [min(D_{fm},D_d)P_d^2 + min(D_{fm}, D_d, D_o)2P_dN_dP_o + min(D_{fm},D_d,D_m)2P_dN_dN_oP_m + min(D_{fm},D_d,D_f)2P_dN_dN_oN_mP_f + min(D_{fm},D_o,D_m)N_d^2P_oP_m + min(D_{fm},D_o,D_f)N_d^2P_oN_mP_f + min(D_{fm},D_m,D_f)N_d^2N_oP_mP_f + min(D_{fm},D_f)N_d^2N_oN_mP_f^2] / P_{oc}$$

Equation 8.12

$$\text{For } X_{min} = 3,\ D = [min(D_{fm},D_d,D_o)P_d^2P_o + min(D_{fm},D_d,D_m)P_d^2N_oP_m + min(D_{fm},D_d,D_f)P_d^2N_oN_mP_f + min(D_{fm},D_d,D_l)P_d^2N_oN_mN_fP_l + min(D_{fm},D_d,D_o,D_m)2P_dN_dP_oP_m + min(D_{fm},D_d,D_o,D_f)2P_dN_dP_oN_mP_f + min(D_{fm},D_d,D_o,D_l)2P_dN_dP_oN_mN_fP_l + min(D_{fm},D_d,D_m,D_f)2P_dN_dN_oP_mP_f + min(D_{fm},D_d,D_m,D_l)2P_dN_dN_oP_mN_fP_l + min(D_{fm},D_d,D_f)2P_dN_dN_oN_mP_f^2 + min(D_{fm},D_d,D_f,D_l)4P_dN_dN_oN_mP_fN_fP_l + min(D_{fm},D_o,D_m,D_f)N_d^2P_oP_mP_f + min(D_{fm},D_o,D_m,D_l)N_d^2P_oP_mN_fP_l + min(D_{fm},D_o,D_f)N_d^2P_oN_mP_f^2 + min(D_{fm},D_o,D_f,D_l)2N_d^2P_oN_mP_fN_fP_l + min(D_{fm},D_m,D_f)N_d^2N_oP_mP_f^2 + min(D_{fm},D_m,D_f,D_l)2N_d^2N_oP_mP_fN_fP_l + min(D_{fm},D_f)N_d^2N_oN_mP_f^3 + min(D_{fm},D_f,D_l)3N_d^2N_oN_mP_f^2N_fP_l]/ P_{oc}$$

Equation 8.13

8.1.5 Customer Disconnection – Size and Unit Cost

Once the largest group of customer sites with $X = X_{min}$ for a given failure mode of an asset has been identified the size of consequence of disconnection of this group must be fully quantified. The weighted quantity of generation disconnected, MW_W is given by:

$$MW_W = \sum \varphi MW_{GTEC}$$

Equation 8.14

Where MW_{GTEC} is the Transmission Entry Capacity (TEC) of each disconnected generator and φ is the design variation weighting factor. This factor equals 1 for generators who are connected with standard SQSS levels of security. Its value for generators with lower than standard levels of security will be determined by each TO. TEC is used without any reference to load factor as this is how generator disconnection compensation is calculated as laid out in the Connection and Use of System Code (CUSC). Secondly the annual average true demand of customers disconnected, MW_D, is calculated by summing the peak demand and the embedded generation contribution during peak of all sites at risk. Both the peak demand and contribution of embedded generation is taken directly from DNO week 24 data submissions. The final inputs are the number of vital infrastructure sites of three different types supplied by sites at risk as shown in Table 8.3. These are demand sites of particular importance in terms of economic or public safety impact. There is no additional quantification of the risk of disconnection of customers or consumers for which the disconnection risks are considered High Impact Low Probability (HILP) events. The risk is treated on a per MW basis like any other consumer or customer.

The lists of sites that belong to the categories outlined in Table are deemed sensitive and thus are not included here. The costs of disconnection per site, per hour were calculated by collecting as much publicly available information as possible on the costs of historic disconnection events of comparable infrastructure sites across the developed world. These costs per hour or per event were converted into current prices through exchange rate and price indexation conversion. An average for each category was then taken.

Estimates used in earlier price controls have been indexed by RPI-CPIH to April 2023.

Vital Infrastructure Category	**Symbol and Cost**		
	Number of Sites	**Cost per site per hour (£/hr)**	**Cost per site per disconnection event (£)**
Transport Hubs	S_T	$V_T = 2{,}346{,}425.90$	-
Economic Key Point	S_E	$V_E = 1{,}816{,}587.80$	-
Particularly sensitive COMAH sites	S_C	-	$V_C = 21{,}407{,}982.57$

Table 8.3

The final component of the risk cost is the *Value of Lost Load (VOLL)*, the per unit cost is separately defined for the three above quantities of customer loss. *VOLL* is expressed in £/MWh. VOLL as used in monetised risk were originally set by a 2012 consultation for OFGEM and BEIS. This has been indexed by RPI-CPIH to a 2023/24 price base, with a value of £26,163.79/MWh.

The cost of disconnection of generation is in two parts, firstly the generation compensation payment cost, G_C, in £/MWh varies with outage duration is based upon the CUSC methodology and uses cost information from the ESO.

For D ≤ 1.5h, $G_c = MW_W D C_{SBP}$

Equation 8.15

For 1.5 h < D ≤ 24h, $G_c = MW_W(1.5C_{SBP} + \{D - 1.5\}C_{SMP})$

Equation 8.16

For D > 24h, $G_c = MW_W(1.5C_{SBP} + 22.5C_{SMP} + \{D - 24\}C_{TNUoS})$

Equation 8.17

Where C_{SBP} is the annual average system buy price in £MWh^{-1}, C_{SMP} is the annual average system marginal price in £MWh$^{-1.}$ C_{TNUoS} is the average Transmission Network Use of System (TNUoS) refund cost per MW per hour. C_{TNUoS} is calculated by dividing the annual TNUoS charge for all generators by the total of TEC of all generators and again by 8760. The assumptions for T3 for these values are discussed in section 5.

Secondly, the cost of generation replacement, G_{R*}, again dependent on *D* is defined as below.

For D ≤ 2h, $G_R = DC_{SMP}(0.42MW_W - 0.62MW_D)$

Equation 8.18

For D > 2h, $G_R = 2C_{SMP}(0.42MW_W - 0.62MW_D)$

Equation 8.19

For $G_R \geq 0$, $G_{R*} = G_R$

Equation 8.20

For $G_R < 0$, $G_{R*} = 0$

Equation 8.21

This cost reflects the expense of the ESO constraining on generation to replace that lost by the disconnection of generation. The equation multiplies the duration of the disconnection and the annual average price to constrain on plant by the mismatch between the expected mismatch between generation and demand disconnected by the event. This mismatch is calculated by first taking the total TEC of generation connected to the customer sites in the group at risk, MW_W, and multiplying it by the system wide average generation load factor 0.42 (calculated by dividing the total energy generated in a year in MWh across the whole system by 8760 and then by the total TEC of all generation on the system). Secondly the peak adjusted demand, MW_D, of all customer sites in the group is multiplied by the average demand factor 0.62 (calculated by dividing the total annual transmission demand in MWh by 8760 and dividing again by the winter peak demand in MW). The difference between these two numbers is the mismatch, multiplied by the System Marginal Price in £MWh^{-1} and the duration up to a maximum of 2 hours. After 2 hours it would be expected that the market would have self-corrected for the generation mismatch.

The vital infrastructure site disconnection cost, *V*, is the numbers of different types of vital infrastructure sites multiplied by the cost per site and in the case of transport and economic key point sites multiplied by *D*.

$$V = D(V_T S_T + V_E S_E) + V_C S_C)$$

Equation 8.22

With all elements of the equation defined, the customer disconnection risk cost, R_{customer}, of a given asset failure mode of any asset can be defined by Equation 34.

$$R_{customer} = P_{oc}[G_C + G_R + 0.62DMW_D VOLL + V]M_z$$

Equation 8.23

A vast majority of lead assets will return a non-zero value for customer disconnection risk, the exceptions being shunt reactors and circuits which connect nodes with more than four circuits. These assets will have material risks for one of the next two elements of system consequence.

8.1.6 Boundary Transfer

This methodology estimates the cost impact of having to pay generation constraint payments in order to restrict flows across a system boundary and in order to do so we make some assumptions. Different assets related to a boundary will have different impacts however for simplicity it is assumed that all assets will have the same impact.

It is also assumed that the impact comes from having to constrain generation on one side of the boundary and dispatch generation on the other side of the boundary; to calculate this we can use some of the same mechanics used for the Customer Disconnection consequence.

In order to calculate the impact of a depletion of a boundary we therefore need to determine by how much flow across is it restricted when a fault occurs. This comes in two stages, firstly the capacity of the boundary must be calculated in different states, secondly it must be determined by home much flow is restricted. For example a boundary may normally be capable of allowing 500MW across it while after a fault it allows 250MW, if the flow required is only 100MW then there is no impact in this case. However, if the required flow is 350 MW, then the impact would be 100MW for the duration of the fault.

Capability of the boundary is obtained through modelling the system and three values are obtained for each modelled boundary, their capability at:

- N-D – one double circuit outage, which is the state to which we plan
- N-D-1 – one double circuit outage and one additional fault
- N-D-2 – one double circuit outage and two additional faults

The probability of larger faults than N-D-2 is assumed to be negligible.

The information about how much capacity is required across a boundary comes from the ESO. As part of the Future Energy Scenarios each year, the ESO calculated Unrestricted Boundary Flows for each boundary. This is how much would flow across the boundary if capacity was not an issue. The data is split up into percentiles which show what the flow would be below for that percentage of the time. For example, if the 75% percentile is 400MW then for 75% of the year the Unrestricted Boundary Flow across that boundary would be less than 400MW.

From these two pieces of information we can calculate the impact of a fault on a boundary which is done using this formula:

$$Impact = \max\,[0, UBF - C_{N-D-x} - \max(0, UBF - C_{N-D})]$$

Equation 8.24

Where:
UBF = Unrestricted Boundary Flow
C_{N-D} = the capacity of the boundary under N-D conditions
C_{N-D-x} = the capacity of the boundary under N-D-x conditions
X = 1 or 2 depending on how many faults on the network

There are three different scenarios, the first is that the UBF is greater than C_{N-D}. In other words the flow is already restricted across the boundary and so a fault will restrict that flow more. The equation under these conditions becomes $C_{N-D} - C_{N-D-x}$ or the difference between the standard capability of the boundary and the restricted capability.

The second scenario is when the UBF is lower than C_{N-D-x}. In this case, even though the capability of the boundary has been reduced, there is no impact as there is still no restriction to the flow across the boundary. The equation under these conditions becomes equal to 0.

The final scenario is that the UBF is less than C_{N-D} but greater than C_{N-D-x} . The flow was not restricted until the fault occurred. In this situation that equation becomes UBF – C_{N-D-x} or the difference between UBF and the restricted boundary capability.

Using the UBF percentiles provides by the ESO, the average restriction at each boundary can be calculated. For a list of percentiles, UBF pairs ($\%_X$, UBF_X) of Y length, the average restriction can be calculated with this equation:

$$Average\ Restriction\ = \sum_{1}^{Y} Impact. (\%_x - \%_{x-1})$$

Equation 8.25

This restriction is calculated for both N-D-1 and N-D-2. The Boundary Transfer System Consequence of the fault can be calculated with the following formula:

$$R_{boundary} = D_{fm}[B_Y(1 - P_{Y+1}) + B_{Y+1}P_{Y+1}]$$

Equation 8.26

Where:
$R_{boundary}$ = Boundary Transfer System Consequence
D_{fm} = Duration of the unavailability of the asset until it is returned to service
B_Y = Average restriction for an N-D-1 fault
B_{Y+1} = Average restriction for an N-D-2 fault
P_{Y+1} = Proportion of the duration of the failure mode that would be spent at N-D-2

The methodology will return non-zero risks for any assets related to a boundary such that their fault would restrict the flow across said boundary.

8.1.7 Reactive Compensation

The third element of the system consequence methodology calculates the cost impact of having reactive compensation unavailable due to a fault or failure of any asset that would render the reactive compensation unusable. This could include circuit breakers, transformers, and cables as well as the compensation itself. The purpose of reactive compensation is to produce or consume reactive power to aid control of system voltage. When compensation equipment is unavailable this reactive power control is either procured from generators instead or elements of the transmission system are de-energised, reducing system resilience.

As a simplification the cost impact of a fault or failure can be quantified as the volume of reactive power not supplied multiplied by the cost per MVArh the ESO must pay to buy the same service from generators. Therefore, we have Equation 8.27 to calculate the reactive compensation system risk cost (RRC) of an asset Failure Mode:

$$R_{RC} = R_F D_{fm} Q C_{MVArh}$$

Equation 8.27

Where

R_F is the requirement factor of the compensation equipment made unavailable or the proportion of the year that the compensation in question is required on a scale of 0 to 1.
D_{fm} is the duration of unavailability due to the asset failure mode.
Q is the capacity of the asset in MVAr.
C_{MVArh} is the average cost of procuring of MVAr from generation sources.

CMVArh will be calculated by taking an annual sum of all costs of generators to absorb MVArs including balancing mechanism actions to bring plant into service and constrain others as well as the cost of providing the reactive absorption itself. This sum is divided by the total number of MVArhs that were absorbed by generators over the year.

8.1.8 High Impact, Low Probability (HILP) Assets

High impact, low probability events are outside the scope of NARM. The network is designed and built to withstand certain levels of faults and failures, as defined in the Security and Quality of Supply Standard (SQSS). A HILP event arising from a single NARM asset event is not considered a credible scenario.

A High Impact Low Probability (HILP) asset will have an element of 'HILP' risk associated with it that is not the same as Asset Risk. An example of a HILP asset may be an asset associated with transmission network black start capabilities or an asset associated with connection of a nuclear site to the transmission network.

The HILP risk will be associated with an event that NGET wish to avoid (e.g. the tripping of a nuclear power station) but one that is also difficult to quantify in risk terms. The probability of such an event is near zero; and the consequences are extremely high. Multiplying anything by near-zero results in near-zero output. Thus, Monetised Risk is not a particularly effective tool for exploring HILP risk.

Application of the NARM Common methodology, described in this NARA and associated supporting documentation, may result in HILP assets ending up lower down in a prioritised list of assets for intervention, based on their Asset Risk.

In instances like this, NGET may choose to intervene on a HILP asset in preference to an asset with an equal or higher Asset Risk and will justify each decision. Note there is no mechanism within NARM to account for such activity.

8.2 Safety Consequence

Within NGET, our safety performance is paramount. This section details how safety consequence is calculated in monetised terms.

When assets fail, they have the potential to cause harm to both the general public and personnel who work on or near to the assets. In circumstances where this happens, there is a cost to society. The aim of this part of the methodology is therefore to capture the safety risks that deteriorating assets present to individuals who are exposed to their effects and the associated cost. Note that NGET also has statutory safety responsibilities, that are not included in the safety consequence, as these tasks must be carried out.

In general, the safety risk for an individual asset can be expressed as shown below:

$$Safety\ Risk = \sum_i \left(P\left(C_{saf,i}\right) \times C_{saf,i}\right)$$

Equation 8.28

Where:
$P\left(C_{saf,i}\right)$ = Probability of failure mode effect i occurring as a result of a failure event
$C_{saf,i}$ = Safety-related costs associated with asset failure resulting in failure mode effect i

For an individual asset the general expression for C_{saf} is as follows:

$$C_{saf} = Probability\ of\ Injury\ \times Cost\ of\ Injury\ \times Safety\ Exposure$$

Equation 8.29

Where:
Probability of Injury = the likelihood that an individual is injured when exposed to the effects of an asset failure
Cost of Injury = the cost associated with an individual sustaining an injury
Safety Exposure = modifier to reflect the number of people who are exposed to the effects of an asset failure

Individuals exposed to asset failures can potentially sustain injuries of varying severity and the likelihood of these injuries occurring will depend on the asset under consideration, the type of failure that occurs and the effects associated with that failure. Moreover, the cost associated with different types of injury will vary. Taking into account these variables the 'Safety Cost' can be more formally expressed as shown below:

$$C_{saf,i} = \sum_{j} Probability\ of\ Injury_{j,i} \times Cost\ of\ injury_{j} \times Safety\ Exposure$$

Equation 8.30

Where:
i = failure mode effect
j = injury type

8.2.1 Failure Mode Effect & Probability of Failure Mode Effect

The failure mode effect represents the possible effects that NGET considers as a result of failure and the probability of failure mode effect represents its likelihood of occurrence. The effects that are considered by NGET and the calculation of their likelihood are described below.

8.2.2 Injury Type & Probability of Injury

Individuals can sustain varying degrees of injury as a result of an asset failure. NGET proposes to categorise the severity of injury into the following types, using HSE definitions[5]:

1. Slight – Injury involving minor cuts and bruises with a quick and complete recovery.
2. Serious - Slight to moderate pain for 2-7 days. Thereafter some pain/discomfort for several weeks. Some restrictions to work and/or leisure activities for several weeks/months. After 3-4 months return to normal health with no permanent disability.
3. Permanent Incapacitating Injury - Moderate to severe pain for 1-4 weeks. Thereafter some pain gradually reducing but may recur when taking part in some activities. Some permanent restrictions to leisure and possibly some work activities.
4. Fatality

The 'Probability of Injury' represents the likelihood that an individual is injured when exposed to the effects of an asset failure. Probabilities will be assigned to each 'Injury Type' considered. The probability assigned to each category will vary depending on the failure mode that occurs and the effects that occur as a result of the failure mode effect materialising. For less disruptive failures there may be no impact from a safety perspective and the probability of injury will be zero. In addition, because it is assumed that the probability of injury applies to an individual, the sum of probabilities across all injury type categories for a failure effect is less than or equal to unity (i.e. an individual's injuries can only be classified under a single category of injury). Examples per failure mode effect are given in the following table.

[5] https://www.hse.gov.uk/enforce/expert/alarpcheck.htm

Asset Type	Event	P(slight)	P(serious)	P(permanent incapacitating injury)	P(fatality)
Tx	01- No Event	0	0	0	0
Tx	02- Environment Noise	0	0	0	0
Tx	03- Reduced Capability	0	0	0	0
Tx	04- Alarm	0	0	0	0
Tx	05- Unwanted Alarm + Trip	0	0	0	0
Tx	06- Transformer Trip	0	0	0	0
Tx	07- Reduced Capability + Alarm + Trip	0	0	0	0
Tx	08- Fail to Operate + Repair	0	0	0	0
Tx	09- Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate	0	0	0	0
Tx	10- Overheating (will trip on overload)	0	0	0	0
Tx	11- Cross Contamination of Oil	0	0	0	0
Tx	12- Alarm + Damaged Component (Tap Changer) No Trip	0	0	0	0
Tx	13- Alarm + Trip + Damaged Component (Tap Changer)	0	0	0	0
Tx	14- Alarm + Trip + Tx Internal Damage	0	0	0	0
Tx	15- loss of oil into secondary containment	0	0	0	0
Tx	16- Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)	0	0	0	0
Tx	17- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement	0	0.551	0.331	0.118
Tx	18- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire	0	0.551	0.331	0.118
CB	01- No Event	0	0	0	0
CB	02- Reduced Function	0	0	0	0
CB	03- Operate Outside Design Parameters	0	0	0	0
CB	04- System effect	0	0	0	0
CB	05- Alarm and lock out (different levels for trip and close)	0	0	0	0
CB	06- Unwanted operation	0	0	0	0
CB	07- Damage to other control circuit	0	0	0	0
CB	08- Replace insulator	1	0	0	0
CB	09- Fail to Operate + Repair	1	0	0	0
CB	10- Disconnector Damage	1	0	0	0
CB	11- Fail to Operate + CB damage + Repair	1	0	0	0
CB	12- Disconnector Failure (End of Life)	0	0	0	0
CB	13- CB failure (end of life)	0	0	0	0
CB	14- Alarm + Trip + Damage + Disruptive Disconnector Failure (Replace)	0.9985	0.0015	0	0

CB	15- overheating high resistance contacts RIDDOR report	0.9985	0.0015	0	0
CB	16- Alarm + Trip + Damage + Disruptive CB Failure (Replace)	0	0.551	0.331	0.118
CB	17- Alarm + Trip + Disruptive Failure + Collateral Damage + Replacement	0	0.551	0.331	0.118
OHL	01- No Event	0	0	0	0
OHL	02- Overheating - reduced function	0	0	0	0
OHL	03- Noise	0	0	0	0
OHL	04- Flashover	0	0	0	0
OHL	05- Trip	0	0	0	0
OHL	06- Component Wear - scheduled repair	0	0	0	0
OHL	07- Conductor Damage and Repair	0	0	0	0
OHL	08- Fittings wear - reduced function	0	0	0	0
OHL	09- Insulator Fails - continues in service	0	0	0	0
OHL	10- Tower defect - repair	0	0.551	0.331	0.118
OHL	11- Fittings Failure (State Requiring Refurbishment)	0	0	0	0
OHL	12- OHL Failure (State Requiring Replacement)	0	0	0	0
OHL	13- Potential Harm	0	0.551	0.331	0.118
OHL	14- Conductor Fall and Trip	0	0.551	0.331	0.118
OHL	15- Conductor Fall, Conductor Remains Live	0	0.551	0.331	0.118
OHL	16- Conductor, Fittings, Steelwork Fall and Trip	0	0.551	0.331	0.118
Cables	01- No Event	0	0	0	0
Cables	02- False Oil Pressure Reading	0	0	0	0
Cables	03- Reduction in circuit rating	0	0	0	0
Cables	04- Loss of pressure (OFC)	0	0	0	0
Cables	05- Trip	1	0	0	0
Cables	06- Component Damage (CSE)	0	0	0	0
Cables	07- Damage to cable	1	0	0	0
Cables	08- Trip + Dielectric Defect (XLPE)	1	0	0	0
Cables	09- Trip + Dielectric Defect (OFC)	1	0	0	0
Cables	10-Loss of Pressure + Loss of oil to environment (OFC)	0	0	0	0
Cables	11- Uncontrolled flashover	0	0.551	0.331	0.118
Cables	12- Accessory Refurbishment	0	0	0	0
Cables	13- Injury or harm	0	0.551	0.331	0.118
Cables	14- Thermal runaway	0	0.551	0.331	0.118
Cables	15- Cable Failure (State Requiring Replacement)	0	0	0	0
Cables	16- Alarm + Trip + Disruptive Failure	0	0.551	0.331	0.118
Cables	17- Alarm + Trip + Disruptive Failure with Fire	0	0.551	0.331	0.118

Table 8.4

8.2.3 Cost of Injury

Fixed costs will be assigned to the different injury types recognised by the HSE as per their website[6], which are inflated to a price base of 2023/24 in line with RPI-CPIH, these are shown in table 12 below.

Whilst the appraisal values reflect a broad range of cost categories, for simplicity of presentation the appraisal values can be divided into two main component costs:

- Human costs - representing a monetary estimate of the loss of quality of life, and loss of life in the case of fatal injuries.
- Financial costs, which are the sum of the following:
  - Productivity costs including:
    - net lost income, taking into account of loss of output and earnings due to absence from work, and offsetting transfers from one party to another, e.g. benefits payments are a cost to Government, but an equal and opposite offsetting benefit to individuals.
    - production costs, such as cost of recruitment and work reorganisation.
  - The cost of Employer's Liability Compulsory Insurance, less compensation pay-outs to individuals
  - Health and rehabilitation costs, such as NHS costs
  - Administrative and legal costs, such as costs of administering benefits claims.

Injury Type	HSE Definitions	HSE 2023/24 Inflated Values
FATALITY		£2,669,968
INJURY		
Permanently incapacitating injury	Moderate to severe pain for 1-4 weeks. Thereafter some pain gradually reducing but may recur when taking part in some activities. Some permanent restrictions to leisure and possibly some work activities.	£4,138,370
Serious	Slight to moderate pain for 2-7 days. Thereafter some pain/discomfort for several weeks. Some restrictions to work and/or leisure activities for several weeks/months. After 3-4 months return to normal health with no permanent disability.	£40,944
Slight	Injury involving minor cuts and bruises with a quick and complete recovery.	£599

Table 8.5

NGET calculates the 'Cost of Injury' as follows:

$$Cost\ of\ Injury_j = \sum Total\ Cost\ (Rounded) \times Disproportion\ Factor$$

Equation 8.31

The 'Total Cost (Rounded)' is reflected by the HSE values, as per their website, which are inflated to a cost-base of 2023/24 in line with RPI-CPIH.

[6] https://www.hse.gov.uk/managing/theory/alarpcheck.htm

A disproportion factor recognises the high-risks that could arise from the nature of the Transmission Industry. Such disproportion factors are described by the HSE guidance when identifying reasonably practicable costs of mitigation. This value is not mandated by the HSE, but they state that they believe that "the greater the risk, the more should be spent in reducing it, and the greater the bias should be on the side of safety"[7].

In the NARA, the Disproportion Factor is set to the maximum value recommended by the HSE of **10**, which reflects the importance NGET places on managing risks to safety.

8.2.4 Safety Exposure

Safety consequences are specific to individual assets and their physical location. Some assets will expose a greater number of people to their failure effects than others depending on the levels of activity near to the asset. The 'Probability of Injury' only considers whether an individual will be injured assuming they are exposed to the effects of an asset failure and does not consider whether it is likely that one or more individuals will be within the vicinity of an asset when it fails. In order to take into account the likely number of people exposed to the effects of an asset failure (e.g. where an event impacts multiple people at the same time) a 'Safety Exposure' modifier is incorporated into the 'Safety Cost of Failure Mode Effects' calculation.

Under the Electricity Safety Quality and Continuity Regulations 2002 (ESQCR), risk assessments must be carried out on NGET assets to assess the risk of interference, vandalism, or unauthorised access to the asset by the public.

The overall safety exposure value is built from the following components:

- Location:
    - Proximity to areas that may affect its likelihood of trespass or interference.
    - Personnel activity in the vicinity of the asset

Location/Exposure Risk Rating	
Low	Limited personnel access. No likely public access
Medium	Regular personnel/public activity in the vicinity of the asset
High	High levels of personnel/public activity in the vicinity of the asset
Very High	Constant personnel/public activity in the vicinity of the asset

Table 8.6

[7] https://www.hse.gov.uk/managing/theory/alarpcheck

The values used for each safety exposure score (Low-Very High), are included below. The following factors have been taken into consideration:

- Number of hours per annum of an individual staff member being in the vicinity of an asset on the system, due to:
  - Routine activities
  - Maintenance activities
  - Replacement activities
  - Switching activities
  - Meetings in substation buildings
  - Office base at substation buildings

- Number of hours per annum to an individual member of the public being in the vicinity of an asset, due to:
  - Domestic activity
  - Industrial activity
  - Rights-of-way
  - Agricultural activity
  - Educational activity
  - Commercial activity
  - Retail activity

The safety exposure factor takes an average value of hours per annum for an individual to be within the vicinity of a NGET asset. This presents an average safety exposure value for each of the four categories, reflective of a ratio of the number of hours per annum for an individual to be within the vicinity of a NGET asset compared to the number of hours in a year. The average value is taken due to the number of NGET sites, such that the sites included in each exposure category can vary significantly, and the category for 'Very High' exposure will contain the anomaly sites with extreme cases of public and staff exposure, significantly higher than the remaining sites within that category. The average value is used as the most appropriate representation of the exposure levels for the majority of sites within each relevant exposure category.

The following table outlines the calculated exposure factors.

Exposure Category	Criteria	Exposure Value
Very High	• Large substation with office accommodation, typically large double busbar substation with several supergrid transformers. • Office accommodation for National Grid employees, with conferencing facilities within close proximity to HV equipment. This is in addition to routine inspections, maintenance activities and switching operations. • Urban environment or adjacent to a power station. • Substation in location where there is constant third party or public activity.	13.88
High	• Large substation with office accommodation, typically large double busbar substation or large mesh substation with multiple supergrid transformers. • Office accommodation for personnel with or without conferencing facilities is not within close proximity to HV equipment but access to these office buildings can take personnel within the vicinity of the HV equipment. This is in addition to routine inspections, maintenance activities, and switching operations. • Rural environment. • Public access within 50m of equipment or building within 50m of equipment.	6.00
Medium	• Large substation, typically double busbar, or mesh substations with at least three mesh corners. • Any permanent site office accommodation is not located within the HV compound. • Activities at site are confined to routine inspections, maintenance activities, and switching operations. • Rural environment. • Public access within 100m of equipment or building within 100m of equipment	0.07
Low	• Small substation, typically a teed connection or single switch mesh. • Activities at site confined to routine inspections, maintenance activities, and switching activities. • Rural environment. • No general access to substation.	0.06

Table 8.7

These values are used to calculate the safety risk for an individual asset. An example now follows for a single failure mode for a transformer on a site with Medium exposure. The values given are dummy values for demonstration purposes.

	P(slight)	P(serious)	P(permanent incapaci-tating injury)	P(fatality)	£(slight)	£(serious)	£(permanent incapaci-tating injury)	£(fatality)	DF	Exp	PoE
Inputs	0	0.551	0.331	0.118	599	40,944	4,138,370	2,669,968	10	0.07	0.02
P*£					0	22,560	1,369,800	315,056			
*DF					0	225,600	12,976,850	3,150,560			
*Exposure					0	15,792	908,379	220,539			
SUM of *Event Consequences*	**1,144,710**										
Event Risk (Cons. * PoE)	**22,894**										

Table 8.8

8.3 Environmental Consequence

Commitments to Net Zero by 2050 are front and centre to both the national agenda and National Grid's stated objectives. Environmental consequence encompasses both local impacts as well as CO_2e emissions. The environmental consequence is calculated by quantifying four categories as a result of a failure mode effect: oil, SF6, waste produced and fire.

When assets fail, they have the potential to impact on the geographical area local to the asset. The aim of this part of the methodology is to capture the different environmental effects that deteriorating assets present and the associated costs. In general the total environmental risk for an asset can be expressed as shown below:

$$Environmental\ Risk = \sum_i \left(P\left(C_{env,i}\right) \times C_{env,i}\right)$$

Equation 8.32

Where:
$P\left(C_{env,i}\right)$ = Probability of failure mode effect i occurring as a result of a failure event
$C_{env,i}$ = Environmental-related costs associated with asset failure resulting in failure mode effect i

For an individual asset the general expression for C_{env} is:

$$C_{env} = Cost\ of\ Environmental\ Impact\ \times Impact\ Volume \times Environmental\ Exposure$$

Equation 8.33

Where:
Cost of Environmental Impact – the costs arising from a failure event that has an impact on the environment.
Impact Volume – the average volume of environmental impact per failure mode effect
Environmental Exposure – modifier to reflect the sensitivity of the environment exposed to the effects of an asset failure event.

In reality, the environment exposed to asset failures can potentially sustain varying severities of environmental impacts, and the likelihoods of these environmental impacts occurring is dependent on the asset under consideration, the type of failure that occurs and the effects associated with the failure. Consequently, the costs associated with different types of environmental impacts will vary. Taking into account these variables the 'Environmental Cost of Failure Mode Effect' can be formally expressed as shown below:

$$C_{env,i} = \sum_j Cost\ of\ Environmental\ Impact_j \times Impact\ Volume_j \times Environmental\ Exposure$$

Equation 8.34

Where:

i	=	Failure Mode Effect
j	=	Environmental Impact Type

8.3.1 Failure Mode Effect & Probability of Failure Mode Effect

The failure mode effects represent the possible effects that NGET considers as a result of a failure event and the probability of failure mode effect represents its likelihood of occurrence. The environmental effects that are considered by NGET and the calculation of their likelihoods are described below.

The probability assigned to each environmental impact type, see section 8.3.2, will vary depending on the failure mode that occurs and the effects that result from the failure mode event materialising. For less disruptive failures there may be no impact on the environment.

The failure mode effect represents the possible effects that TOs consider because of failure and the probability of failure mode effect represents its likelihood of occurrence.

8.3.2 Cost of Environmental Impact

The Cost of Environmental Impact is calculated as an average cost where there is loss of oil, loss of a CO2 equivalent gas, fire and/or generation of waste for each failure mode effect. The following costs are applied to each environmental impact component.

The sources for the above costs are given in the following table. Source values have been adjusted for RPI-CPIH to a price base of 2023/24.[8] As with other consequence values, these parameters are fixed for the duration of RIIO-T3 for reporting purposes.

Input	Fixed Value	Source
Environmental cost per litre oil (£/litre)	50.48	This value is shared with the DNO CNAIM, page 81: https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf
Traded carbon price (£/t)	426	Ofgem ET3 CBA Template
Environmental Cost of Fire	7,210.56	The value used in the DNO CNAIM, page 81: https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf
Environmental Cost per Tonne Waste	216.32	The value used in the DNO CNAIM, page 81: https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf

Table 8.9

[8] https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/chaw/mm23

An example of the environmental risk of a cable of medium exposure now follows. Please note the figures are for demonstration purposes only.

Event	Oil Lost (l)	SF6 Lost (kg)	Waste (dry weight, tonne)	Number of Fires	Environmental Consequence for Failure Mode Effect	Exposure Score	Environmental Risk
CBL12 - Trip + cable system damage + fire	123.3	0	0.3	1	£13,499.64	2	£26,999.28

Table 8.10

8.3.3 Environmental Exposure

Due to the distributed nature of networks, it is important that exposure is taken into account. Environmental consequences are specific to individual asset size and their physical location. Some assets pose a greater risk to the environment than others. In order to account for this an 'Environmental Exposure' modifier is incorporated into the 'Environmental Consequence of Failure Mode Effect' calculation.

8.3.4 Location Factor

Location factor allows for an adjustment to be made based on an assessment of the environmental sensitivity of the site on which an asset is located. The specific concerns will vary by asset type but include proximity to watercourses and other environmentally sensitive areas. The factor also recognises any mitigation associated with the asset. This factor is derived by combining separate factors relating to proximity to a watercourse or Site of Special Scientific Interest (SSSI).

Environmental Exposure Category	Criteria	Exposure Score
Low	• Asset located in controlled environment	1
Medium	• Asset may be located in controlled, environment which may be located within 100m of environmentally sensitive area. • Distributed asset located greater than 100m from sensitive environment	2
High	• Distributed asset, all, or part of which, is located within 100m of Source Protection Zone, abstraction, or surface water course or SSSI	10

Table 8.11

8.4 Financial Consequence

The financial cost of failure is driven by the cost of investigation, repair, and replacement of an asset.

When assets fail, they have the potential to impact on the geographical area local to the asset. The aim of this part of the methodology

The Financial Consequence of Failure is derived from an assessment of the typical replacement and repair costs incurred by the failure of the asset in each of its applicable Failure Modes and is multiplied by the probability of each Failure Mode effect.

$$Financial\ Risk\ (k) = \sum_i \left(P\left(C_{fin,i}\right) \times C_{fin,i}\right)$$

Equation 8.35

Where:

$P\left(C_{fin,i}\right)$ = Probability that event i occurs
$C_{fin,i}$ = Financial consequence of the event's effect

The FMEA process identifies asset items and the failure events associated with them. Each failure event may result in one or more Failure Mode effects and each effect has consequences. The probability of the events resulting from each Failure Mode is determined through the FMEA process.

The Financial Consequence for each effect is derived from the average cost to repair or replace the asset (or assets if the failure results in a disruptive failure where adjacent assets are damaged) based on existing repair and replacement data. The costs presented are the labour and repair costs as well as OMGS (Other Materials, Goods and Services), which are necessary to carry out the repair or replacement of the failed asset. Additional costs, associated with the failure but not incurred in carrying out the repair or replacement, such as environmental clean-up or formal incident investigation costs (undertaken following catastrophic failures, for example), are not considered as part of the Financial Consequence.

For RIIO-T3, Financial Consequences concerning unit costs of asset replacement use standardised values common with the other TO's. This is intended to improve the comparability of risk outputs. NGET's OHL Fittings are expressed in per/km terms, whereas the other TO's have expressed their input in per set terms.

To illustrate, the following Failure Mode effects result from events associated with transformers. It is the event which has the consequence; hence the costings are derived for each event. In order to validate the costing, the Failure Modes which cause the event are also presented.

Event	Connected with Failure Mode/cause	Activities used to derive average cost (this table will show actual costs in the Licensee Specific Appendix following CTV)
01- No Event		
02- Environment Noise	Noise caused by anti-vibration pads failing or faulty fans	Labour costs and component costs plus OMGS
03- Reduced Capability	Downratings due to pumps/fans failure or overheating caused by carbon build up on tap changers	Labour costs to investigate and repair. Component costs + OMGS
04- Alarm	Overheating alarm	Labour costs for alarm investigation
05- Unwanted Alarm + Trip	Unintentional operation of Buchholz or WTI	Labour costs for trip investigation
06- Transformer Trip	high-res contacts on diverters	Labour costs for trip investigation
07- Reduced Capability + Alarm + Trip	Overheating due to WTI failure. Contactor/control relay failure Pump failure Fan failure Incorrect valve position Blockages (sludging) cooler blockage external OR loss of oil due to tank corrosion	Labour costs to investigate and repair. Component costs + OMGS
08- Fail to Operate + Repair	Buchholz or WTI fail to trip or alarm, overheating on tap changers,	Labour costs to investigate and repair. Component costs + OMGS
09- Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate	Tap changer motor drive defects	Labour costs to investigate and repair. Component costs + OMGS
10- Overheating (will trip on overload)	Overheating due to carbon build up or high resistance contacts in tap changer or overheating due to WTI failure Contactor/control relay failure Pump failure Fan failure Incorrect valve position Blockages (sludging) cooler blockage external	Labour costs to investigate and repair. Component costs + OMGS
11- Cross Contamination of Oil	Gasket leak, drive seal failure, corrosion on diverters	Labour costs to investigate and repair. Component costs + OMGS
12- Alarm + Damaged Component (Tap Changer) No Trip	Diverter mechanism jams due to loose permali nuts	Labour costs to investigate and repair. Component costs + OMGS. May necessitate replacement of tap changer.
13- Alarm + Trip + Damaged Component (Tap Changer)	Selector/diverter fail to complete op or flashover. Diverter open circuit, loss of containment	Labour costs to investigate and repair. Component costs + OMGS. May necessitate replacement of tap changer.
14- Alarm + Trip + Transformer Internal Damage	Selector/diverter fail to complete operation or flashover. Diverter go open circuit, loss of containment - but in this case the transformer is damaged not just the tap changer	Labour costs to investigate and repair. Component costs + OMGS. Significant damage to the transformer windings.
15- loss of oil into secondary containment	Major oil leak, tank breach	Labour costs to investigate and repair. Component costs + OMGS.
16- Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)	End of Life owing to deterioration	Unit cost for replacement of the asset
17- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement	Disruptive failure - potential for bushing porcelain projectiles	Replacement of the asset plus costs of replacing/repairing any adjacent assets damaged
18- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire	Transformer fire	Replacement of the asset plus costs of replacing/repairing any adjacent assets damaged by the fire

Table 8.12

9 Methodology for Calculation of Risk

This section defines how the probabilities and consequences described in previous sections are combined to calculate risk.

For a given asset (k), a measure of the risk associated with it is the Asset Risk (A_k), given by:

$$Asset\ Risk(A_k) = \sum_{j=1}^{n} P(C_j) \times C_j$$

Equation 9.1

$where:$
$P(C_j) = Probability\ of\ consequence$ j $occurring\ during\ a\ given\ time\ period$
$C_j = the\ moetised\ Consequence\ j$
$n = the\ number\ of\ Consequences\ associated\ with\ Asset\ k$

Figure 16 shows how the components interact and combine together to arrive at a value for Asset Risk.

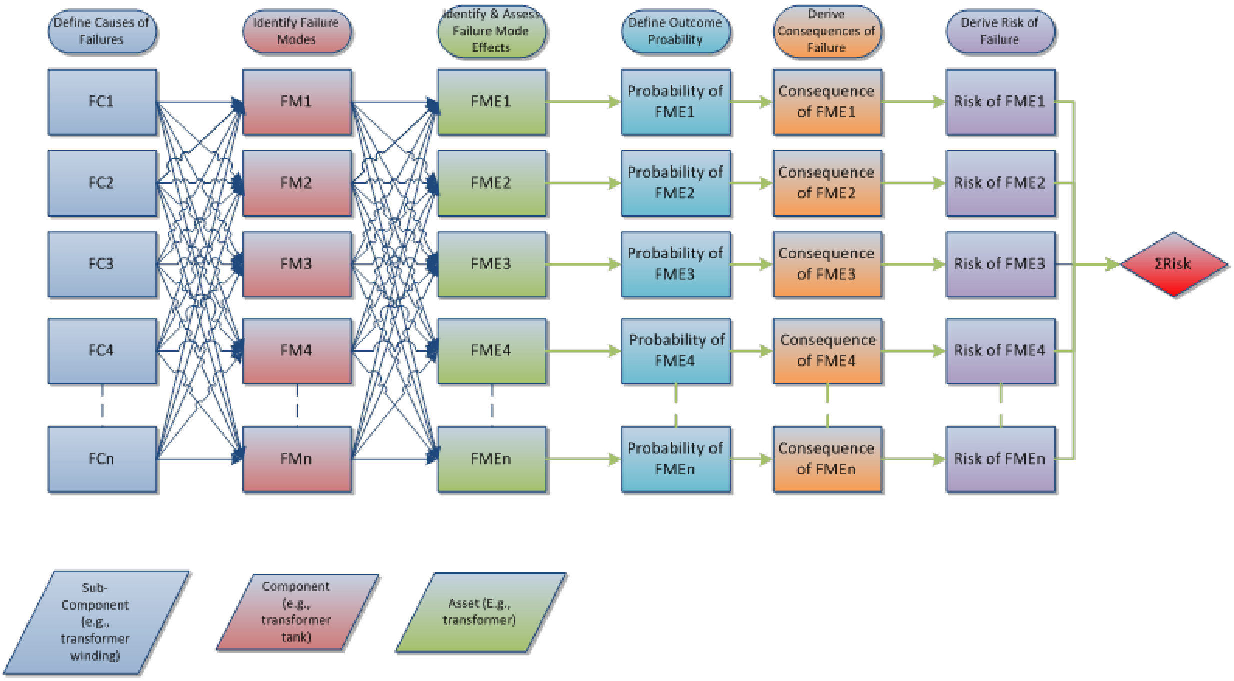


Figure 9.1

The Network Risk for NGET can be calculated by summing the Asset Risk associated with each lead asset as shown in Equation 50.

$$Network\ Risk = \sum_{k=1}^{n} A_k$$

Equation 9.2

BS EN 60812 describes the process for disaggregating systems into their component parts and assessing the probability of functional failures of each component and the consequences of such failures, then aggregating these quantities to obtain an estimate of the overall risk of the system. A failure mode is clearly immaterial if the cost of the analysis of the failure of a component is much greater than value of the risk represented by the failure of that component, because either the probability of failure of a component or the consequence of failure of a component is insufficiently large.

The available evidential and supporting data, suitable for FMEA analysis, is usually imperfect. This may be for a number of reasons, for example, some possible effects and consequences might be material, but have not yet occurred. Similarly, accurate data may not have been captured for failures, even though the effects and consequences have occurred. Effective application of FMEA therefore requires engineering expertise, both to envision material consequences that have not yet occurred and to estimate values which have not been measured and/or recorded and which cannot be reliably calculated from first principles.

There is a further requirement in the Ofgem Direction[9] to enable the identification of all material factors contributing to real or apparent performance against targets.

A non-exhaustive list of these factors is identified in Paragraph 32 of the Direction. In practice, the effect of any of these factors will be a modification to one or more inputs to the methodology. Any factor which does not result in a modification to one or more of the inputs does not contribute to real or apparent performance against targets as measured by this methodology.

For factors that do modify one or more inputs to the methodology, the methodology can be re-run incorporating these input changes and the outcomes compared with the outcomes produced before the changes are applied. Hence not only can factors be identified but also their relative materiality can be determined.

Therefore, if NGET (or Ofgem) suspects that a factor (e.g. data revisions) or change in external environment (business, legal, site or situation) will contribute to real or apparent performance against targets, then the following tests can be made:

1. Check what impact the factor has on existing inputs to the methodology – if the impact is zero then the factor has been positively classified as non-material.
2. If impact is non-zero, then re-run the methodology with changed inputs and compare outputs with equivalent outputs with the un-changed inputs – The variation of output can be compared with the variations produced by other factors and ranked in terms of relative materiality.

[9] Ofgem (2016) *Decision to direct modifications to the electricity transmission Network Output Measures Methodology.* Available at: < https://www.ofgem.gov.uk/publications/decision-direct-modifications-electricity-transmission-network-output-measures-methodology>

10 Decision Support for Intervention Planning

Failure modes can be addressed by different interventions including maintenance, repair, replacement, and refurbishment. Not all these options are applicable to all assets or failure modes.

Certain types of intervention will address particular failure modes. These may be routine interventions, such as maintenance, or specific, such as planned replacements.

The available interventions for managing the performance of assets range from routine maintenance to full replacement.

These activities are undertaken to ensure the longevity and performance of the NGET network. Without effective management of these activities, and understanding the related interactions between them, NGET would, in time, experience deterioration of network outputs which would have a significant detrimental impact on the capability of the network.

Intervention plans are optimised to deliver an efficient level of network risk in line with customer, consumer, and stakeholder expectations. In determining this efficient level, NGET evaluates the cost of interventions against the benefits these interventions deliver.

In determining an intervention plan in any period, NGET needs to assess the Asset Risks and decide exactly which interventions to undertake. This requires NGET to make a binary decision (e.g. to replace, or not to replace) where every asset has an Asset Risk contribution to the Network Risk. This process involves assessing all available interventions to decide the combination which most efficiently manages Network Risk.

The cost of these interventions is not equal to the reduction in Network Risk achieved by undertaking that intervention plan.

Table 20 identifies different types of intervention that would address failure modes, Figure 17 (not to scale) illustrates which failure modes are addressed by the different intervention types.

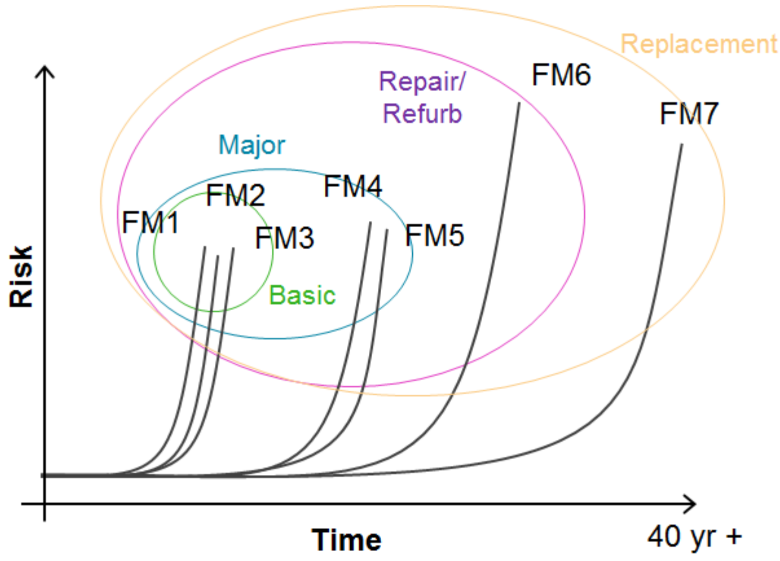


Figure 10.1

Failure Mode	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Basic Maintenance	✔	✔	✔	✗	✗	✗	✗
Major Maintenance	✔	✔	✔	✔	✔	✗	✗
Repair	✔	✔	✔	✔	✔	✔	✗
Refurbishment	✔	✔	✔	✔	✔	✔	✗
Replacement	✔	✔	✔	✔	✔	✔	✔

Table 10.1

Several failure modes can happen within a similar time frame/ duty cycle, so the work to be carried out needs to be selected carefully in order to:

- Ensure that the relevant failure modes are adequately addressed.
- Reduce the whole life cost.
- Limit the impact of constraints such as outages and resources.

Interventions are determined by understanding how to prevent failure modes and the collection of data to predict failures. Knowing the asset's position on each failure mode curve enables NGET to make a targeted intervention specifically addressing those failure modes most contributing to the risk. Following the intervention the asset risk on the asset is reduced for that particular failure mode.

10.1 Maintenance

The purpose of asset maintenance is to ensure that relevant statutory and legal requirements are met, such as those relating to safety and environmental performance, keeping assets in service, as well as allowing NGET to gather condition information so that performance risks are better understood and mitigated.

Through maintenance activities NGET can manage the natural deterioration of asset condition so that the assets remain operable throughout their anticipated technical life, reducing unplanned outages on the network as well as monitoring the condition of assets to improve understand of their performance. This then feeds into future asset intervention plans.

Maintenance is a fundamental tool in NGETs' management of network reliability, safety, and environmental performance (and hence customer satisfaction). Reducing maintenance to zero, or reducing levels without undertaking impact assessments, would lead to a decline in the condition of assets (this effect is seen more rapidly than for under-investment in replacement), leading to increased unplanned events and in some cases bringing forward the need for asset replacement or increasing refurbishment activities.

Maintenance policy evolves as processes and practice are periodically reviewed. NGET reassess maintenance policy on an ongoing basis using the latest information available in order to ensure assets can achieve their anticipated asset lives and reduce the potential for unplanned disruption. Maintenance activity can uncover developing trends for defects, ensure rectification of unforeseen functional failure modes and can be the driver for further innovation in methodologies and techniques for future interventions.

When developing maintenance content, NGET has a systematic, structured method for cost/benefit evaluation. This includes understanding the asset's reliability for known failure modes, taking account of how the operating costs would be expected to increase during the time between interventions; identifying potential changes in performance; and consideration of the impact that a change to the intervention might have on the life of the asset. As part of the planning process, maintenance is bundled into efficient packages to optimise access to the network and the assets.

Maintenance activities are pro-active interventions which take place at regular intervals according to policy. Undertaking maintenance activities ensures that the assets function correctly and can identify issues with the assets which can be addressed prior to a failure mode occurring.

A basic maintenance will involve basic checks for function of particular components as well as activities such as visual inspections, checks for fluid/gas levels where appropriate.

An intermediate maintenance takes place at longer intervals than a basic and will include all activities undertaken for a basic maintenance but will include additional checks on specific components of the equipment.

A major maintenance will include all the activities undertaken for a basic and intermediate maintenance but will also include comprehensive and possibly intrusive work as well as more exhaustive checks. These take place less regularly than basic and intermediate levels and generally require a significantly longer outage to carry out the work.

Maintenance interventions are determined through maintenance policy for each asset type, according to the specific requirements for that asset. Newer assets tend to follow manufacturer recommendations and warranty requirements. With experience, intervals and specific maintenance tasking can evolve from the original recommendations.

10.2 Repair

Repair is generally a reactive activity responding to a failure mode event when it has occurred or, in some cases, to prevent a particular failure mode if it can be detected before the event occurs. For some failure modes which cannot be detected on a routine basis, such as by maintenance or inspection, repair is the only available intervention once the failure mode has occurred. That is not to say that detection of the failure mode is not available, and assets are monitored for known failure modes. For example, cable oil pressure is monitored, and an alarm triggered if the pressure falls below a certain level. The failure mode is detected as the oil leak initiates but there are no routine interventions available to detect the occurrence of a leak before it occurs.

The only available option is to repair the cable when the oil leak is detected. Some failure modes, which lead to another failure mode, can be detected prior to failure, for example, sheath testing of cables will reveal defects in the oversheath which, if left unrepaired, will eventually lead to the corrosion of the sheath and subsequently an oil leak. A repair intervention can then be planned to mitigate this risk.

10.3 Refurbishment

The decision to refurbish instead of replacing an asset follows careful consideration of a number of criteria. For refurbishment to be technically feasible and cost-effective, the asset population size must be sufficiently large because the costs associated with developing the technical content of a refurbishment procedure, and the set-up costs to undertake the work, mean that it is difficult to make refurbishment of small populations cost-effective.

The ongoing lifetime cost of supporting a refurbished asset family must also be considered. It may be more cost-effective to replace highly complex units that require frequent intervention.

Continuing spares support must be considered. Whilst some spares can be re-engineered without significant risk, this is not appropriate for performance critical components. If such components are unavailable (or not available cost-effectively), refurbishment is unlikely to be a realistic option.

Additionally, the condition and deterioration mechanisms of the asset class must be well understood. If these criteria are met, and it is considered that refurbishment is a viable option, it would be expected that refurbishment activities would change the asset's condition and/or extend asset life.

10.4 Replacement

Individual assets or families, which are deemed to be a priority given their risk, trigger the need for replacement and capital investment. There may also be instances where the frequency of repair (and associated cost) is such that replacement is considered economic. To facilitate the development of an optimised replacement plan, priority ranked lists for replacement are created for each asset type.

11 Calibration, Testing and Validation

The TOs jointly completed a detailed Calibration, Testing and Validation (CTV) for end-of-life failure modes.

The NARM methodology has been designed to enable the parameters to be easily adjusted to reflect the results of the CTV exercises. The CTV exercises include scenarios and tests, and defined criteria are set out prior to the test and the results are compared against these criteria. A summary of the CTV elements and results can be found in appendix B.

11.1 Calibration

The purpose of calibration is to:

- Ensure that each TO produces credible CoF, EoL modifiers and PoF values that are representative of the impacts of actual asset failures.
- Ensure that each TOs input values and assumptions are consistent and comparable.

11.2 Testing

The purpose of testing is to:

- Ensure that each TO has implemented correctly in line with the NOMs methodology.
- That the each TOs implementation of the NOMS methodology works across a suitable range of credible scenarios.

11.3 Validation

The purpose of validation is to:

- Ensure that each TOs implementation of the NOMs methodology produces comparable results.
- Ensure that the NOMs methodology produces realistic and credible values.

11.4 Delivery of CTV

The TOs have worked together to compare the performance of their respective risk models.

A separate document was produced following CTV detailing the work carried out and data sources used; listing the calibration that has been applied as a result of CTV and demonstrate comparability across TOs. Issue 4 of the NARA incorporated the findings of the CTV exercise.

12 Asset Specific Details

12.1 Circuit Breakers

12.1.1 Background

Circuit breakers generally have limited condition information on an individual asset basis. To gather additional condition information on sub-components and assemblies that have the potential to affect the end of life (EoL) modifier, would require invasive work to assess actual condition. It is not economically favourable to do this for every single asset and each of its failure mode items, based on the balance of intervention cost and failure risk.

Non-outage, non-intrusive diagnostic techniques, including continuous monitoring, do not detect all failure mode effects linked to the end of life of circuit breakers and also have economic limitations (e.g. it is not necessarily favourable to retrofit all gas circuit breakers with permanent online monitoring).

The distribution of deterioration within a population is impacted by equipment environment, electrical and mechanical duty, maintenance regime and application.

In this methodology a family specific deterioration component to the EoL modifier formula is introduced to account for missing condition information. Assignment to family groupings is through identification of similar life limiting factors. Family groupings are broadly split into interrupter mechanism types.

Known deterioration modes have been determined by carrying out analysis of materials and components during replacement, refurbishment, maintenance, and failure investigation activities or following failures. The output of the analysis reports has been used to both inform and update the relevant deterioration models. Anticipated technical asset lives are based on the accumulated engineering knowledge of NGET's defect and failure statistics and manufacturer information. The method for mapping this knowledge to the end-of-life curve was presented in the failure modes and effects analysis section.

12.1.2 Deterioration

Circuit breakers are made up of several sub-components or assemblies. These deteriorate at different rates, are different in relation to their criticality to the circuit breaker function and finally have different options regarding intervention.

Although there is a correlation between age and condition, it has been observed that there is a very wide range of deterioration rates for individual units. The effect of this is to increase the range of circuit breaker condition with age, some circuit breakers becoming unreliable before the anticipated life and some showing very little deterioration well after that time.

12.1.3 Air-blast Circuit Breakers

Using the above approach, refurbishment has, in selected cases, proven to be an effective way to extend the Anticipated Asset Life (AAL) for Conventional Air-Blast (CAB) and Pressurised head Air Blast (PAB) circuit breakers.

The replacement of ABCBs is considered alongside the remaining lifetime of the associated site air system. If removal of the last ABCBs at a site allows the site air system to be decommissioned, early switchgear replacement may be cost beneficial when weighed against further expenditure for air system replacement and/or on-going maintenance.

Cost-benefit analysis of eliminating ABCB should also consider the benefit of eliminating the complex and expensive air systems they are associated with. The risk model does not know about these elements, and such decisions have to be considered externally.

Air- blast circuit breakers are technologically obsolete, and out of manufacture. A replacement at this time at 400kV or 275kV would likely be an SF6-type breaker, although alternative SF6-free circuit breakers are coming to market.

12.1.4 Oil Circuit Breakers

The life-limiting factor of principal concern is moisture ingress and the subsequent risk of destructive failure associated with the BL-type barrier bushing in bulk Oil Circuit Breakers (OCBs). A suitable replacement bushing can be exchanged when moisture levels reach defined criteria, but at a high cost to the extent that it is not economically favourable to replace many bushings within the population. Risk management of bushings has been achieved by routine oil sampling during maintenance, subsequent oil analysis and replacement of bushings and even whole circuit breakers where required.

Bulk Oil circuit breakers are obsolete, and out of manufacture. Similarly, to air-blast circuit breakers the alternative technology presently for 275kV units (our highest design voltage in this class) is an SF6 gas circuit breaker.

12.1.5 SF6 Gas Circuit Breakers

Gas Circuit Breakers became widespread in their application from the early 1980's. They are compact, with fewer breaks per phase and a much simpler mechanism and interrupter assembly when compared with air blast circuit breakers. Consequently, their ongoing maintenance costs are comparatively low. There is a correlation between time in service, operating environment and SF6 emissions. This poor environment performance is a driver for investment in this population, alongside deterioration of operating mechanisms, interrupter assemblies and obsolete control systems. A similar process to that followed for the ABCB families is being undertaken to identify refurbishment (i.e. life extension) opportunities. Where this is not technically feasible or cost-effective, replacement is planned. The availability of SF6 alternatives is factored into this decision making.

The GCB population includes a diverse range of smaller families, with variants and differing operating regimes, and so the identification of large-scale refurbishment strategies may not be cost-effective. Technical and economic evaluation as well as further development of refurbishment strategies will take place.

A significant number of SF6 circuit-breakers which are installed on shunt reactive compensation are subject to very high numbers of operations (typically several hundred per year). The "end of life" of these circuit-breakers is likely to be defined by number of operations ("wear out") rather than age-related deterioration. To assist with asset replacement planning, these circuit-breakers have been assigned a reduced asset life in this document based on a prediction of their operating regime. Different asset lives have been assigned depending on the circuit breaker mechanism type and/or if the circuit breaker has been reconditioned; in each case the asset life is based on an operating duty of 300 operations per year. It is currently proposed to recondition most types of high duty reactive switching circuit breaker when they have reached their anticipated asset life based on the number of operations they have performed.

12.1.6 Circuit Breaker EoL modifiers - Examples

These examples previously appeared in the Licensee-specific appendices. They have been anonymised for inclusion in the public document.

12.1.6.1 Circuit Breaker Example 1

The breaker is a Reyrolle OB14 Air Blast Circuit Breaker, installed in 1961. The design and support from the OEM are considered as Obsolete, with a declining population of grey spares. Historically, this class of breaker has a known history of end-of-life failure modes, which when combined with the declining population of components aligns to the asset family assumptions of a 45-year lifespan.

$$EOLmod = \max\left(AGE_{FACTOR}, DUTY_{FACTOR}, SF6_{FACTOR}, DEFECT_{FACTOR}, FAMILY_{FACTOR}\right)$$

Equation 12.1

This asset is classed as in poor condition based on the data that is available. Its EoL modifier score is 100.
Due to both design and maintenance regime, operational duty, fault current and SF6 are not determining factors in application of EoL modifier.

12.1.6.2 Circuit Breaker Example 2

The breaker is a GEC FE2 275kV gas circuit breaker, which is assigned to the 300kV gas circuit breaker, hydraulic mechanism group. It has an anticipated asset lifetime of 30 years. Family level assessment of the hydraulic systems including the nitrogen accumulator and operating mechanism has identified life-limiting factors of these major components.

Examples include seal deterioration within the mechanism, leading to reduced performance in time of operation, and the gradual loss of nitrogen pressure within the accumulator due to leakage or passing of hydraulic fluid. Furthermore, a significant number of FE circuit breakers have an electronic control system, the life of which is limited. The Mk1 variant of the control system has demonstrated significant life limiting factors requiring replacement of this functionality for ongoing reliable operation.

Other factors include the number of operations performed (1819) which is approaching the upper limit for this mechanism type and demonstrating a low-level of continuous SF6 leakage. While the total is low, the leak rate is nonetheless significant resulting in a EoL modifier of 60 being applied for this characteristic alone.

The breaker was installed in 1987, 30 years old as of 2017. Time in service is a factor in assessment of the asset risk and leads to an overall EoL modifier of 83.

12.1.6.3 Circuit Breaker Example 3

Installed in 1993, this asset is a Reyrolle SPD2 400kV GIS asset. The age and operational duty do not play a major factor. The asset has demonstrated an increasing trend of SF6 leaks; to the point that in 2017 it had leaked 22kg of SF6. While this is low compared to the overall inventory of the gas zone, the leak rate is ~4% and has EoL modifier 60 for this factor alone.

Intervention on this asset will be completed to OEM recommendations and depending on the location of the leakage, either changes to the seals and desiccants, or, if there is corrosion of flanges, machining to remove imperfections may be required.

12.1.6.3 Circuit Breaker Example 4

This asset is amongst the oldest GIS installations on the National Grid system. Its design is obsolete, and the OEM does not support the asset. This example has exceeded the anticipated lifetime of 30, by 13 years, which immediately leads to an EoL modifier of 100. The score is validated further by the SF6 leakage score; the gas zone is reported to be leaking over 100kg per year leading to an EoL modifier of 100. Replacement of the asset was recommended.

12.2 Transformers & Reactors

12.2.1 Background

Transformers and reactors share similar end of life mechanisms since they are both based on similar technologies. The same scoring method is therefore applied to calculate the EoL modifier. For simplicity within this section the term transformer is used to mean both transformer and reactor.

Transformers are assigned an EoL modifier according to the condition inferred from diagnostic results, the service history, and postmortem analysis of other similar transformers.

The health of the overall transformer population is monitored to ensure that replacement/refurbishment volumes are sufficient to maintain sustainable levels of reliability performance, to manage site operational issues associated with safety risks and to maintain or improve environmental performance in terms of oil leakage.

The process by which transformers are assigned an EoL modifier relies firstly on service history and failure rates specific to particular designs of transformers and secondly on routine test results such as those obtained from Dissolved Gas Analysis (DGA) of oil samples. When either of these considerations gives rise to concern, then where practicable, special condition assessment tests (which usually require an outage) are performed to determine the appropriate EoL modifier. Special condition assessment may include the fitting of a continuous monitoring system and the analysis of the data to determine the nature of the fault and the deterioration rate.

The elements to be taken into account when assigning an EoL modifier are:

1. Results of routine condition testing
2. Results of special condition assessment tests
3. Service experience of transformers of the same design, and detailed examination of decommissioned transformers
4. Results of continuous monitoring where available

The following additional condition indications shall be taken into account when deciding the repair/replacement/refurbishment strategy for a particular transformer:

1. Condition of oil
2. Condition of bushings
3. Condition of coolers
4. Rate of oil loss due to leaks
5. Condition of other ancillary parts and control equipment
6. Availability of spare parts particularly for tap-changers

12.2.2 Deterioration

Thermal ageing of paper is the principal life limiting mechanism for transformers which will increase the failure rate with age. This failure mechanism is heavily dependent on design and evidence from scrapped transformers indicates a very wide range of deterioration rates. Knowledge of the thermal ageing mechanism, other ageing mechanisms and the wide range of deterioration rates are used to define the anticipated asset lives for transformers.

In addition to the above fundamental limit on transformer service life, experience has shown that a number of transformer design groups have inherent design weaknesses which reduce useful service life.

The condition of transformers can be monitored through routine analysis of dissolved gases in oil, moisture, and furfural content together with routine maintenance checks. Where individual test results, trends in test results or family history give cause for concern, specialist diagnostics are scheduled as part of a detailed condition assessment. Where appropriate, continuous monitoring will also be used to determine or manage the condition of the transformer.

Methods exist to condition assess transformers and indicate deterioration before failure, however the time between the first indications of deterioration and the transformer reaching a state requiring replacement is varied and can depend on factors such as the failure mechanism, the accuracy of the detection method, and the relationship between system stress and failure. For this reason the transformer models periodically require updating (supported by evidence from post-mortem analysis) as further understanding of deterioration mechanisms is acquired during the transformer life cycle.

12.2.3 Insulating Paper Aging

The thermal ageing of paper insulation is the primary life-limiting process affecting transformers and reactors. The paper becomes brittle, and susceptible to mechanical failure from any kind of shock or disturbance. Ultimately the paper will also carbonise and cause turn to turn failure, both mechanisms leading to dielectric failure of the transformer. The rate of ageing is mainly dependent upon the temperature and moisture content of the insulation. Ageing rates can be increased significantly if the insulating oil is allowed to deteriorate to the point where it becomes acidic.

The thermal ageing of paper insulation is a chemical process that liberates water. Any atmospheric moisture that enters the transformer during its operation and maintenance will also tend to become trapped in the paper insulation. Increased moisture levels may cause dielectric failures directly or indirectly due to formation of gas bubbles during overload conditions.

The paper and pressboard used in the construction of the transformer may shrink with age which can lead to the windings becoming slack. This compromises the ability of the transformer windings to withstand the electromagnetic forces generated by through-fault currents. Transformer mechanical strength may be compromised if it has experienced a high currents through faults during its lifetime and the internal supporting structure has been damaged or become loose.

End of life as a result of thermal ageing will normally be supported by evidence from one or more of the following categories:

1. Post-mortem (scrapping) evidence (including degree of polymerisation test results) from units of similar design and load history.
2. High and rising furfural levels in the oil
3. High moisture content within the paper insulation
4. Evidence of slack or displaced windings (frequency response tests or dissolved gas results)

12.2.4 Core Insulation

Deterioration of core bolt and core-to-frame insulation can result in undesirable induced currents flowing in the core bolts and core steel under certain load conditions. This results in localised overheating and risk of Buchholz alarm/trip or transformer failure as free gas is generated from the localised fault. It is not normally possible to repair this type of fault without returning the transformer to the factory. Evidence of this end-of-life condition would normally be supported by DGA results together with evidence from decommissioned transformers of similar design. Insertion of a resistor into the core earth circuit can reduce or eliminate the induced current for a period of time.

13.2.5 Thermal Fault

Transformers can develop localised over-heating faults associated with the main winding as a result of poor joints within winding conductors, poor oil-flow or degradation of the insulation system resulting in restrictions to oil flow. This is potentially a very severe fault condition. There is not normally a repair for this type of fault other than returning the transformer to the factory. Evidence of this end-of-life condition would normally be supported by dissolved gas results together with forensic evidence from decommissioned transformers of similar design.

12.2.6 Winding Movement

Transformer windings may move as a result of vibration associated with normal operation or, more commonly, as a result of the extreme forces within the winding during through fault conditions. The likelihood of winding movement is increased with aged insulation as outlined above. Where evidence of winding movement exists, the ability of the transformer to resist subsequent through faults is questionable and therefore the unit must be assumed not to have the strength and capability to withstand design duty and replacement is warranted. There is no on-site repair option available for this condition. Winding movement can be detected using frequency response test techniques and susceptibility to winding movement is determined through failure evidence and evidence of slack windings through dissolved gas results.

12.2.7 Dielectric Fault

In some circumstances transformers develop dielectric faults, where the insulation degrades giving concern over the ability of the transformer to withstand normal operating voltages or transient overvoltage. Where an internal dielectric fault is considered to affect the main winding insulation, irreparable damage is likely to ensue. This type of condition can be expected to worsen with time. High moisture levels may heighten the risk of failure. Evidence of a dielectric problem will generally be based on operational history and post-mortem investigations from units of similar design, supported by DGA. Various techniques are available to assist with the location of such faults, including partial discharge location techniques. If evidence of an existing insulation fault exists and location techniques cannot determine that it is benign, then the transformer should be considered to be at risk of failure.

12.2.7 Corrosive Oil

In certain cases, high operating temperatures combined with oil containing corrosive compounds can lead to deposition of copper sulphide in the paper insulation, which can in turn lead to dielectric failure. This phenomenon may be controlled by the addition of metal passivator to the oil, however experience with this technique is limited and so a cautious approach to oil passivation has been adopted. Regeneration or replacement of the transformer oil may be considered for critical transformers or where passivator content is consumed quickly due to higher operating temperatures.

12.2.8 Transformer Case Study 1

No acetylene and normal levels of gas in main tank. Score zero (0).

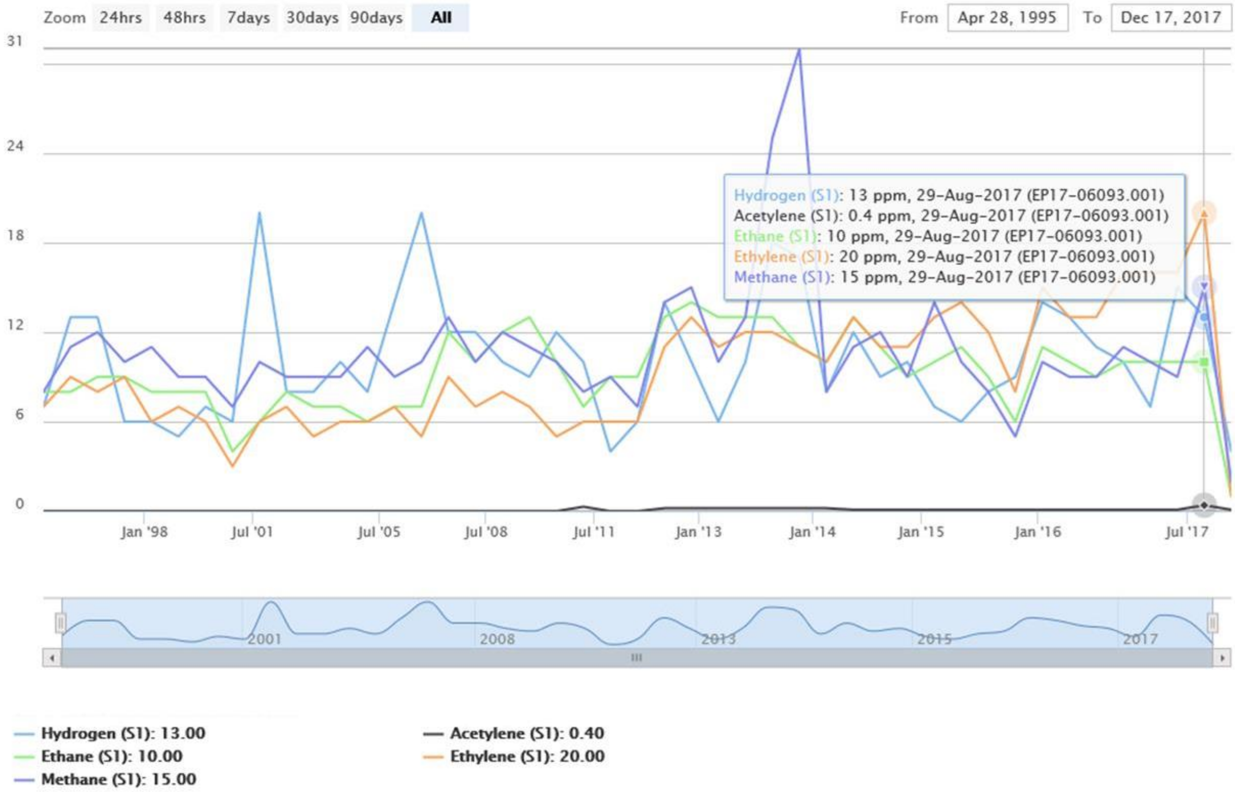


Figure 12.1

12.2.9 Transformer Case Study 2

Low levels of acetylene in main tank since commissioning. EoL Score 2.

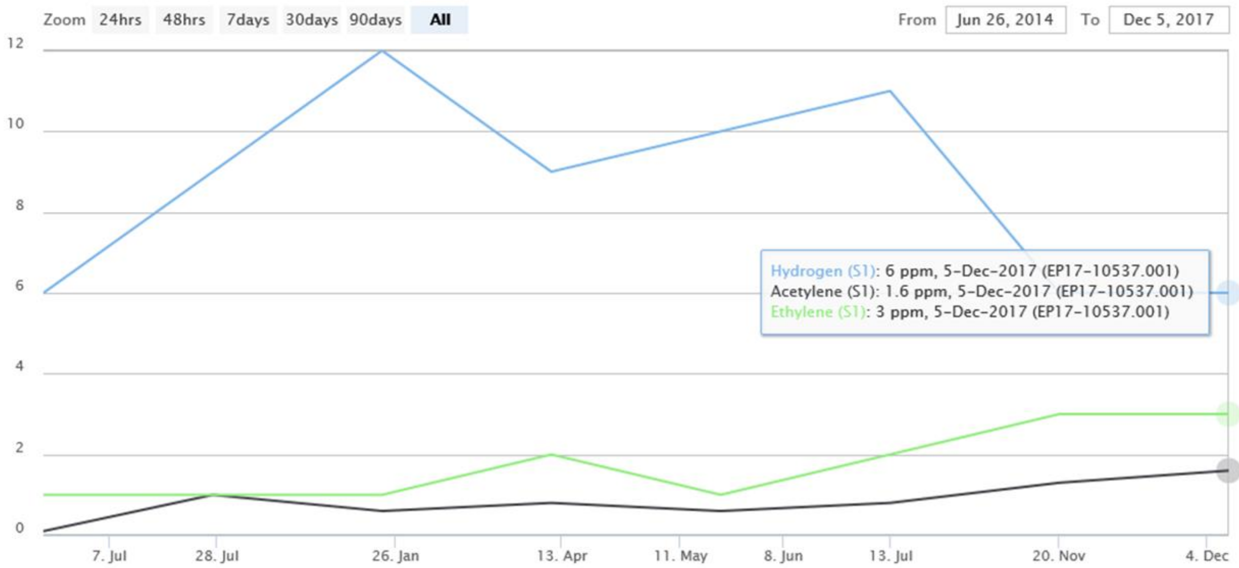


Figure 12.2

12.2.10 Transformer Case Study 3

Installation from 2012. Evidence of low-level arcing/sparking fault. Repair being managed under warranty. EoL score 10.

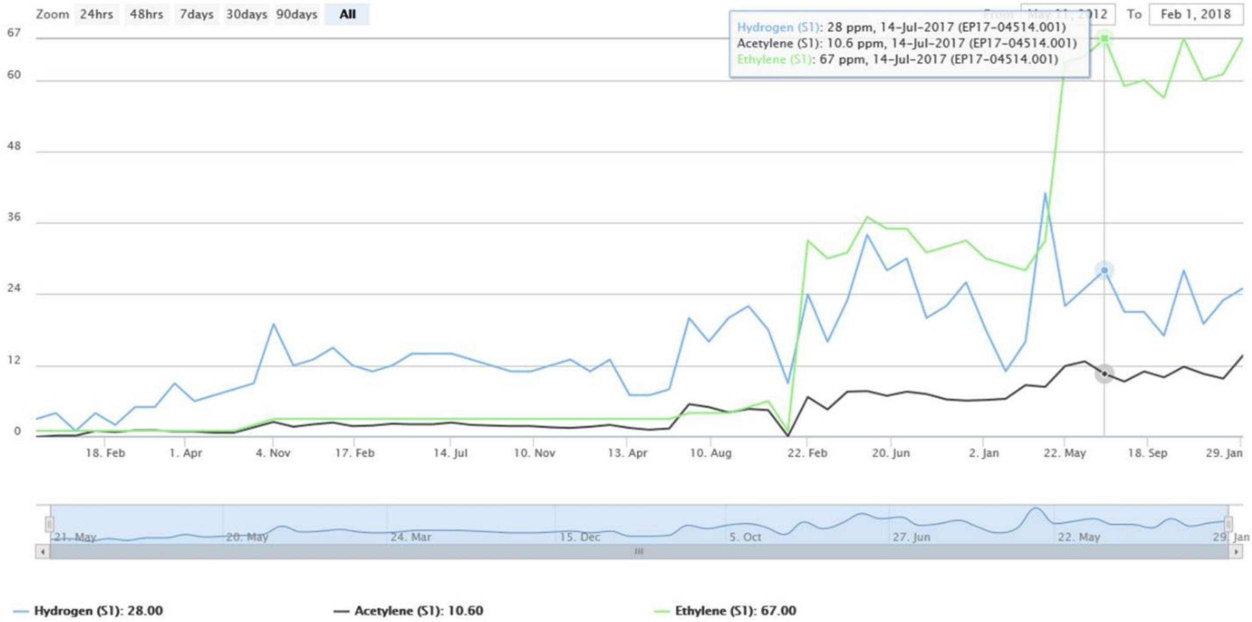


Figure 12.3

12.2.11 Transformer Case Study 4

Evidence of overheating fault in main tank. The bushings were changed in 2014/15, however gas is trending up again.

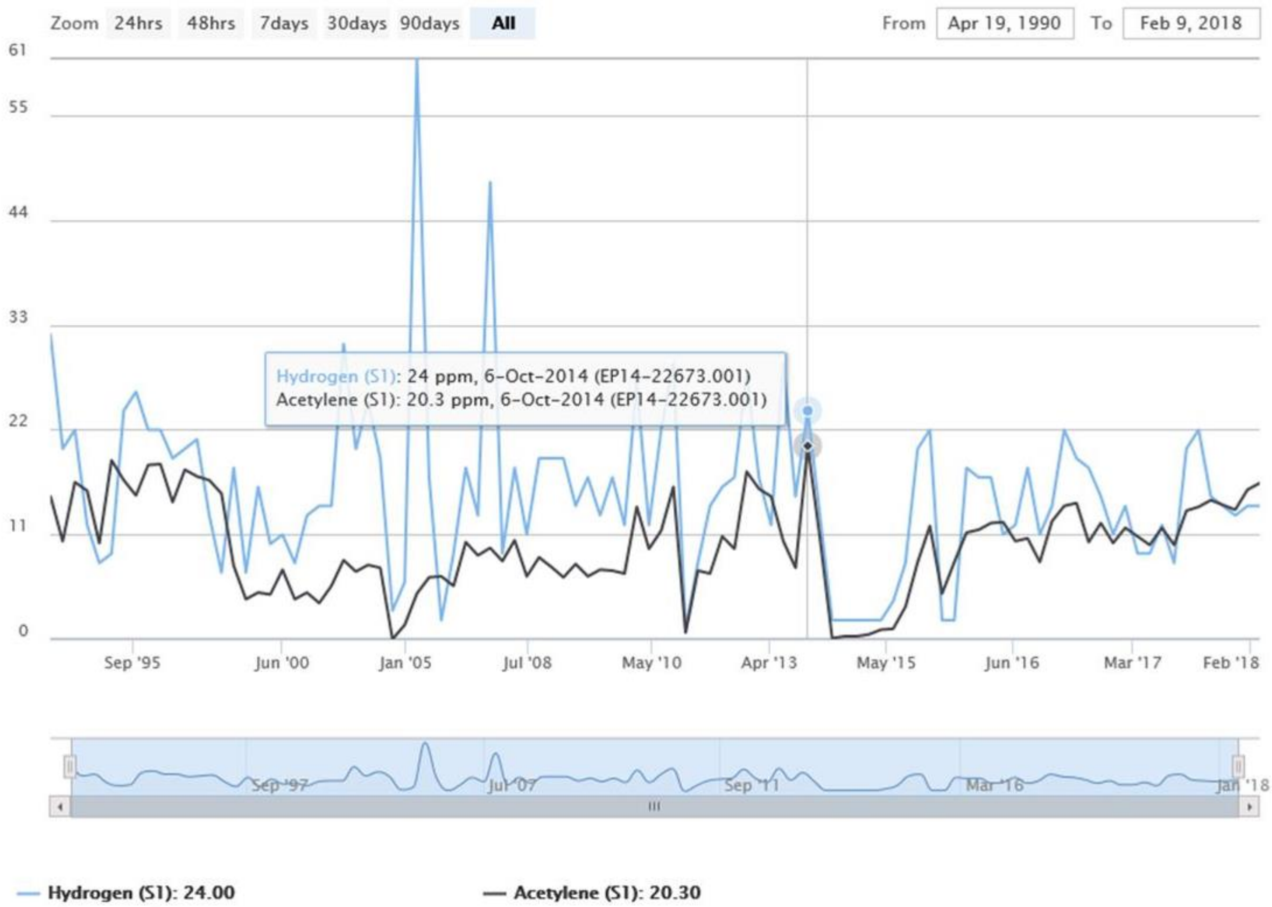


Figure 12.4

12.2.11 Transformer Case Study 4

This unit was installed in 2014. There is evidence of a worsening arcing/sparking fault in the high acetylene level. A repair is being managed under warranty.

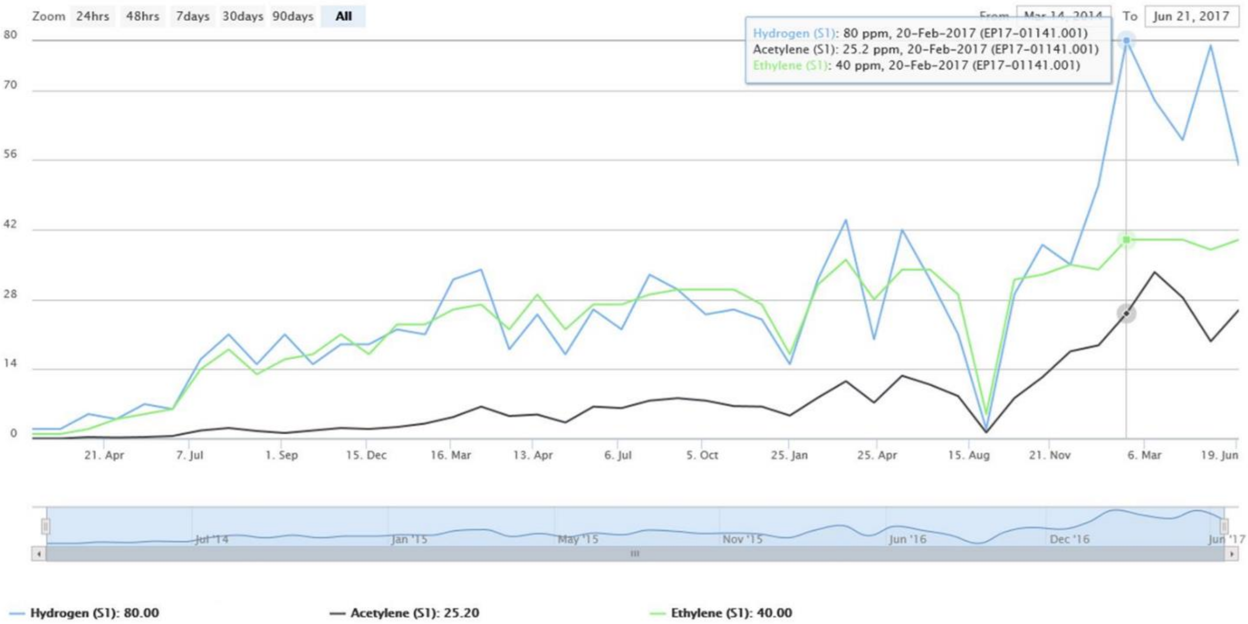


Figure 12.5

12.3 Cables

12.3.1 Background

Cable system replacements are designed such that elements of the cable systems are replaced when the safety, operational or environmental risks of continued operation meet defined criteria. Not all components are reflected in the NARM risk model; and other interventions may prove necessary over time such as the replacement of cable sealing ends, oil systems or re-making of joints.

The condition of a cable system, by nature, is difficult to quantify. Reactive measures to evaluate cable condition, such as the nature and quantity of defects are well established. Pro-active measures for cable condition are less readily available. Technology readiness levels are low, and while there are a number of promising technologies, there is not presently an all-encompassing scientific consensus on the application of condition monitoring technologies in respect of cable lifetime assessment. The opportunities to dissect a cable are rare; and non-invasive inspection techniques are, with few exceptions (e.g., sheath testing), not well proven in respect of lifetime assessment. The end-of-life assessment of underground cables therefore continue to be heavily reliant on reactive measures.

Efforts to develop techniques for assessment continue to be the subject of research & industry bodies. Recent work such as CIGRE B1 working group publications, e.g. TB 912 further the debate.

This update to NARA seeks to rectify issues in the cable scoring methodology based on the latest research and NGET experience, as part of ongoing continuous improvement efforts.

Four main issues are identified with the RIIO-T1 and T2 methodology:

1) The first term of the “ACS Equation” is age itself; with age dominating the output.
2) The second term of the “ACS Equation” is the “Generic Family Reliability” multiplier, applied as a function of age and asset family rather than a direct measure of condition.
3) Certain elements of the overall cable scoring methodology added little or no score; or were not practical to apply at scale. For example, with regards to annual load data; this was analysed by exception where we had cause to believe a circuit was affected by high loading.

4) For each component of the equation there are corresponding scoring tables (e.g. defect count). The modal value of the number of defects in the cable portfolio is zero and the response to defect count was highly stepped as illustrated below.

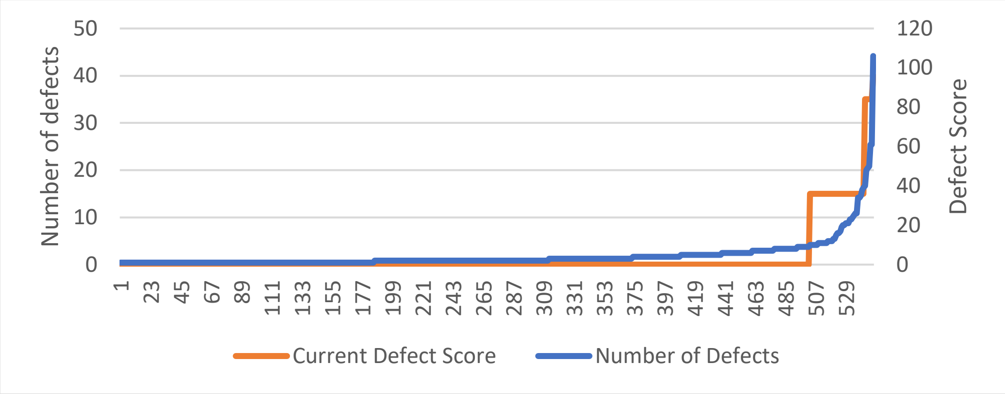


Figure 12.6 – Number of Defects to Defect Score, sorted by assets in good to poor condition (Left-Right)

Given that defects are one of the most important indicators of condition, the method given for use in RIIO-T3 differentiates more between defect rates. This should result in fewer, sudden changes in condition assessment over time, representing a more graduated response as information is accumulated.

Factors considered when determining an EoL modifier include:

1. Historical environmental performance
2. Historical unreliability
3. Risk of tape corrosion or sheath failure
4. Results of condition assessment and other forensic evidence
5. Service experience of cable systems of similar design
6. Number of defect repairs
7. Number of cable faults
8. Expenditure
9. Bespoke issues associated with specific cable systems; examples may include geophysical phenomena such as subsidence or erosion; or civil engineering factors external to the cable, that impact condition.

This list of factors is not exhaustive. Should new evidence come to light of a previously unconsidered factor, due consideration will be given to further updating this Annex.

12.3.2 Deterioration

End of technical life will generally be due to the deterioration of the main cable system. This will typically be the result of a loss of mechanical or electrical integrity leading to severe and unresolvable reliability issues. Given the lead time for constructing a new cable are long, often 5+ years, NGET never wants to reach this state. We need to pre-emptively identify assets sufficiently ahead of time to plan for a replacement.

Globally, cable systems have generally given reliable operation. There is relatively limited experience of long-term deterioration mechanisms. A brief discussion of known failure mechanisms is given below.

Cables can be split broadly into two classes for the purposes of understanding the end of life of this asset class, fluid filled cables and solid dielectric cables. In general, the cable circuit will only meet the criteria for replacement where refurbishment as described above will not address condition and performance issues and guarantee compliance with statutory requirements.

12.3.3 Cable End-of-life Mechanisms

12.3.3.1 Lead and Aluminium Sheath Deterioration

Fatigue and intercrystalline cracking, and defects introduced during manufacture can cause oil leaks to develop. It is generally not possible to predict when a given cable section will fail as a result of this failure mode. Local repairs are not generally effective as sheath deterioration is usually distributed along the cable. End-of-life is reached where sheath deterioration is resulting in significant and widespread oil-loss (relative to duties in respect of recognised code of practice) along the cable length.

Cable oversheaths may be at risk of deterioration as a result of abrasion following thermo-mechanical forces incurred in operation. Performance of oversheath materials have in a limited number of cases been identified as a potential source of problems for the sheath.

12.3.3.2 Bonding Systems

Water ingress to link boxes causes deterioration of cross-bonding systems and leaves the link box and its Sheath Voltage Limiters (SVLs) vulnerable to explosive failure under fault conditions. Specific evidence shall be gathered through condition assessment to support end-of-life determination. This issue will in general be addressed by replacement of specific components during circuit refurbishment activity or routine maintenance.

12.3.3.3 Cooling Systems

Where installed, the life of a cable's cooling system is usually shorter than the lifetime of the cable conductor. Therefore, mid-life intervention may be required to replace the cable cooling system components. While this is not the end of the life of the cable, it is an important consideration as the cable is not able to do what it was designed to do with a failed cooling system. Cooling systems tend to be of bespoke design and hard to classify in the context of an asset family FMEA. Where present, loss of the cooling capacity can reduce circuit rating by 40%. Aluminium cooling pipes are vulnerable to corrosion and plastic pipes are vulnerable to splitting, which can result in water leaks. Cooling control system and pumping equipment will also require replacement prior to the main cable system in line with circuit specific assessment. In general cooling pipework is managed through maintenance to achieve the asset life of the main cable system.

12.3.4 Fluid Filled Cable End of Life Mechanisms

12.3.4.1 Reinforcing Tape Corrosion

Reinforcing tapes are used to retain the oil pressure for cables with lead sheaths. Corrosion of the tapes in certain early BICC cables and AEI cables results in the tapes breaking, the sheath splitting and consequential oil leaks. Methods have been developed for predicting failure using corrosion rates determined through sampling in combination with known operating pressures, and also using degradation mechanism models. Local repairs are not considered effective mitigation as corrosion is likely to be distributed along the cable. We consider the end-of-life of the cable system to be in advance of widespread predicted tape failure. The lead times for cable replacement schemes can be considerably greater than the time to deteriorate from broadly acceptable to unacceptable cable system performance for this failure mode. This implies that pre-emptive action is required to minimise the likelihood of failure occurring. Acceptable performance is where the cable can be repaired on an ad-hoc basis; unacceptable performance is where the corrosion is distributed along a significant number of sections of the route.

The majority of cables vulnerable to this type of corrosion are already programmed for replacement, with relatively few examples to be retained beyond 2030.

12.3.4.2 Stop Joint Deterioration

Stop-joint failure presents significant safety, reliability, and environmental risk. End-of-life for stop joints will be justified based upon oil-analysis data or forensic evidence from similar designs removed from service. Stop joint deterioration can be addressed via refurbishment and would not alone drive replacement of the cable system.

12.3.4.3 Cable Joint Deterioration

In general cable joint deterioration can be addressed via refurbishment and would not alone drive replacement of the joint or cable system.

12.3.4.4 Oil ancillaries

Corrosion of oil tanks, pipework and connections, and pressure gauges can result in oil leaks and incorrect operation of the ancillaries. Specific evidence shall be gathered through condition assessment to support end-of-life determination. This issue will in general be addressed by replacement of specific components during circuit refurbishment activity or enhanced routine maintenance.

Oil systems are likely to be outlasted by the cable conductors they support.

12.3.4.5 Environmental Considerations

NGET has a statutory obligation to comply with the Water Resources Act 1991/Water Resources (Scotland) Act 2013 and to fulfil its commitments, with respect to its Environmental Statement. Utilities demonstrate compliance with the requirement of the Act through adherence to the guidance provided.

A factor to consider in determining anticipated asset life is when it is no longer reasonably practicable to comply with the requirements of the above legislation and guidance and maintain a sustainable level of circuit availability.

12.3.5 Solid, XLPE Insulated Cable End of Life Mechanisms

Transmission circuits have been installed at 132kV and 275kV since 1988 in the UK. Limited examples at lower voltages in substations exist back to 1968. Globally, there is only limited service experience at 400kV or above. These types have mostly been installed over similar time frames to the NGET asset base. The existing asset lifetime estimates are largely based on the tests conducted at type registration, e.g. the time to fault when tested at voltages greater than that intended for operational use. Statistics were then used to justify the probability a cable would reach a specific age. End of life mechanisms have not been encountered in the UK at this time.

Possible failure modes[10] that XLPE cables may exhibit are:

- Insulation deterioration due to natural ageing due to thermal cycling, mechanical aggression, and defects.
- Polyethylene oversheaths have known risks of photo- and thermal-degradation into lactones, esters, ketones, and carboxylic acid.
- Water treeing, arising from partial discharge in a cable. This failure mode arises mostly as a result of moisture ingress, which itself can arise from outer sheath damage, poor or non-existent water barriers or outer metallic sheath corrosion. It should be noted that moisture can penetrate even an intact oversheath; albeit Polyethylene is a much better barrier than PVC as used on older cable technologies.
- Electric treeing due to a defect in the insulation, partial discharge, or thermal ageing. Such a defect could also occur at cable joints as the risk of contamination is considerably higher for such an assembly in the field rather than the clean-room conditions of the production line.
- Arcing from phase conductor to the outer sheath. Such a fault is unlikely without external influences, such as excessive mechanical force on the cable sheath, or deformation of the conductor and insulation.
- Thermal runaway, in the event that the material surrounding the cable does not possess the thermal conductivity and heat capacity appropriate to the losses encountered on the cable. Thermal runaway is possible as a result of third-party influences; for example where burial depths are unintentionally increased without notification.

NGET does not at this time have experience of all these failure modes. Circuit loadings inherent to design of the system to the SQSS in routine operation, are relatively low. The populations are also relatively young. The failure modes listed are highly interlinked, for example the condition and quality of the cable installation have bearing on the risk of water treeing and arcing. The deterioration of the insulation appears mostly to be associated with the age of the cable, though operational duty and installation environment also appear to have bearing on condition. Research has been published in a number of journals concerning the effect of long-term operation at high temperature and the change in chemical composition and insulation effectiveness over time. Evaluation of condition is, unfortunately, problematic without destructively testing the cable, there is therefore a strong desire to devise and deploy alternative means of evaluating condition rather than relying on age as an indicator alone.

12.3.6 Cable End-of-life Modifier examples

12.3.6.1 Cable End-of-life Modifier example 1

This cable was installed in 1980. It belongs to type 1 cable i.e., Lead sheath and PVC over sheath (not AEI and pre 1973 BICC). An anticipated asset life (AAL) of 60 years applies to this type of cable.

EoL modifier is defined as the summation of cable condition score (CCS) and accessories condition score (ACS) and is given by

$$EoL_{mod} = CCS + ACS$$

Equation 12.2

Where

CCS = $AAL_C * GFR + \max(DEFECTS, PRDEFECTS) + COST + ACCESS + \max(OIL, PROIL) + MAIN\ ADJ$

Equation 12.3

$$\text{ACS} = \text{Sum of risk score associated with (Link box, joints, SVL, oil system, Cooling system)}$$

Equation 12.4

In this example, CCS = (0*1) + 60 + 30 + 0 +10 +20 = 120

[10] *EA Technology - Reducing Failure Rates and Better Management of Underground Cable Networks*

GFR weighting is 1 because of the presence of the Category 1 cable.

The circuit has experienced 42 defects in the last 10 years, assigned a score of 60 for its operating history. Repair cost from 2016 sums up to 1.5M and hence scores 30. Around 500 litres of oil leaked in 10 years and hence oil leak scores 10. Main adj includes laying environment issue and multiple sheath faults which scores 20.

There have also been historical failures of the stop joints (EoL 10) and cooling system (EoL 5) on these cables. ACS is therefore set to 15. EoL is capped to 100 and therefore this cable scores EoL of 100.

This asset is being replaced entirely by new, alternative routes and will eventually be decommissioned.

12.3.6.2 Cable End-of-life Modifier example 2

This circuit is one of the poorest condition cable assets, with an EoL modifier that would total 198. The score is capped at 100, as with all asset categories.

It was installed in 1967 and is a Category 3 cable with known propensity to bronze tape corrosion. It's anticipated lifetime is 55 years. Planning for replacement of this asset began in the late 2000's. The lead time for constructing the replacement is in excess of 10 years. It is a strong example of why early intervention planning may be necessary, even before condition indicators can provide certainty to the decision to intervene.

CCS = (15*1.5) + 60 + 30 + 5 +30 +20 = 168

This asset has experienced 95 defects in the last 10 years, and so scores 60 for that. Cost spent repairing defects is high at 0.6M, so scores 30. Oil leaks totalling 400 litres have been reported, scoring 30 (pro-rated oil score of 10). Main Adj score is 20 due to tape corrosion. These issues sum together to drive the EoL modifier score towards a high value. This case demonstrates how a substantial number of issues can aggregate together to push a cable asset towards a state requiring replacement.

ACS factors applicable to this cable include risks associated with stop joint failure (5), SVL failure (5) and cooling stations faults (20). The sub_adj total is therefore 30.

The overall EoL modifier score is therefore 168 + 30 = 198; capped at 100.

12.3.6.3 Cable End-of-life Modifier example 3

This circuit has been assigned a relatively good condition EoL modifier of 28. The oldest cable was installed in 1960 and is of Category of type 1. The oversheath is of obsolete Hessian construction leading to issues with repairability, it is therefore assigned 1.5 for GFR. Age and family issue scores 7.5. There have been 5 defects in the last 10 years (EoL modifier 10). Oil leaks around 30l in 10 years and scores 5 (PROIL =10) and hence assigns a score of 10 for oil leaks. All other scoring components score zero. Even while considering the circuit's advanced age and known issues, it remains a relatively low replacement priority.

12.4 Overhead Lines

12.4.1 General Approach

Routes are fully refurbished, or have critical components replaced, to maintain reliability (including a level of resilience to extreme weather conditions), operational risk and safety performance. In addition, conductors should retain sufficient residual mechanical strength to facilitate safe replacement by tension stringing methods at end of life.

Technical asset lives for OHL components in various environments have been predicted using historical condition information from previous OHL replacement schemes, condition samples taken on existing assets, and an understanding of deterioration mechanisms.

Scoring assessments are made on sections of circuit that are typically homogenous in conductor type, installation date and environment.

12.4.1.1 Deterioration of Conductors

Conductor end of life condition is a state where the conductor no longer has the mechanical strength (both tensile and ductility) required to support the combination of induced static and environmental loads.
Two main deterioration mechanisms exist:

1. Corrosion, primary cause pollution either saline or industrial
2. Wind induced fatigue, common types.
    a. Aeolian vibration (low amplitude high frequency oscillation 5 to 150 Hz)
    b. sub-conductor oscillation (bundles conductors only) produced by forces from the shielding effect of windward sub-conductors on their leeward counterparts.
    c. galloping (high-amplitude, low-frequency oscillation)
    d. wind sway

Conductor fatigue is usually found at clamp positions where the clamp allows more inter-strand motion within the conductor, leading to fretting of the internal layers. Loss of strand cross-section follows, then fatigue cracking, and finally strand breakage. This form of degradation is generally the life-limiting factor for quad bundles, clamping positions on twin bundles can also be affected.

Conductor corrosion is also usually found at clamp positions. Interwoven conductor strands open up at these points allowing for easier ingress of corroding chlorides, sulphates, and moisture etc. The zinc galvanising of the core wires is corroded, eventually exposing the underlying steel. A galvanic corrosion cell is then created where the aluminium wire is sacrificial. The loss of cross section of aluminium leads to greater heat transfer to the steel core increasing the risk of core failure. Additionally, some spacer clamps with elastomer bushings that contain carbon and have a low resistance also lead to galvanic corrosion of aluminium strands, reducing thickness, strength, and ductility.

In addition end of life may be advanced, in rare instances, due to an unexpected load or events such as extreme weather.

12.4.1.2 Deterioration of Insulators

The end of life occurs when the increased risk of flashover (loss of dielectric strength) reaches an unacceptable level due to condition, which may or may not result in mechanical failure of the string, or a decrease in mechanical strength due to corrosion of the steel pin.

12.4.1.3 Deterioration of Fittings – Spacers, Spacer Dampers & Vibration Dampers

The functional end of life of spacers, spacer dampers and vibration dampers occur at the point at which the conductor system is no longer protected, and conductor damage starts to occur.

These items are utilised to protect the conductor system from damage. The main deterioration mechanism is wear or fatigue induced through conductor motion. Corrosion in polluted environments can also be an issue particularly inside clamps.

Wear damage to trunnions and straps of suspension clamps occurs due to conductor movement. The wear has been greatest in areas of constant wind, i.e. higher ground, flat open land and near coasts. For quad lines, in particular at wind exposed sites, wear can be extensive and rapid failures of straps, links, shackles and ball-ended eye links can occur. This is one of the best indicators of line sections subject to sustained levels of wind induced oscillation and hence where future conductor damage is likely to become a problem.

Most conductor joints for ACSR have been of the compression type, although bolted joints are used in jumpers. Overheating joints can arise from inadequate compression along the length of the joint, mainly due to either poor design or installation problems. These allow moisture penetration and oxidation of the internal aluminium surfaces between the joint and conductor. The resistive aluminium oxide reduces the paths for current flow and may cause micro-arcing within the joint. The consequence of this deterioration is that the joint becomes warm which further increases the rate of oxidation. Over a period of time, the resistive paths can result in excess current flowing in the steel core of the conductor, which can then overheat and rupture.

12.4.1.4 Deterioration of Semi-Flexible Spacers

These are fitted in the span and the semi-flexibility comes from either elastomer liners, hinges or stranded steel wire depending on the manufacturer. End of life is defined by perishing of the elastomer lining or broken/loose spacer arms. These allow for excessive movement of the conductor within the clamp leading to severe conductor damage in small periods of time (days to months, depending on the environmental input). The elastomer lining of the Andre spacer type also causes corrosion of conductor aluminium wires due to its carbon content and subsequent galvanic corrosion. A common finding of conductor samples at these positions is strands with significantly poorer tensile and torsional test results. This is a hidden condition state unless it manifests in broken conductor strands that are visible on inspection.

Replacement of these spacers has been necessary on routes that are heavily wind exposed at approximately 25 years. There are many examples still in service beyond their anticipated life of 40 years where visual end of life characteristics have not yet been met. As the condition of the associated conductor within or near the clamp can remain hidden, certain families of this type of spacer such as the ‘Andre’ are identified for the increased risk they pose to conductor health.

12.4.1.5 Deterioration of Spacer Dampers

As the service history of spacer dampers is limited, extensive data on their long-term performance and end of life is not yet available. The spacer arms are mounted in the spacer body and held by elastomer bushes. This increased flexibility should provide the associated conductor system with more damping and greater resilience to wind induced energy. End of life criteria will be defined by broken/loose spacer arms that allow for excessive movement of the conductor/clamp interface.

12.4.1.6 Deterioration of Vibration Dampers

Stockbridge dampers have always been used for the control of Aeolian vibration, a minimum of one damper being installed at each end of every span on each sub conductor. For long spans (where specified by the manufacture) two or more may be used. End of life is defined by loss of damping capability which is visually assessed in the amount of ‘droop’ in and wear of the messenger cable between damper bells. The useful life of a damper is constrained by wind energy input and corrosion of the messenger wire connection with the damper bells. In areas of high wind exposure there is evidence that dampers have required replacement after 10 to 15 years. There are however many more examples of dampers operating beyond their anticipated life with no visual signs of end of life.

12.4.2.1 OHL Conductor EoL Modifier example 1

The formula described in the methodology for EoL is given as the following. The components and details of this formula are also described.

$$PRE_{HS} = W_{FAM} * \max(JNT_{SCORE}, REP_{SCORE})$$

Equation 12.5

For this example, for this asset, W_{fam} = 2.93, consisting of 20 spans. 5 repairs have been carried out, therefore the repair score is 0.25, and the jointing score is 5.

This gives PRE_{HS} = 2.93*max(5, 0.25) = 14.65.

12.4.2.2 OHL Conductor EoL Modifier example 2

This asset had sufficient conductor sample data to prompt the use of the secondary health score. All of the environmental categories relevant to this installation have been sampled sufficiently to qualify. This means the sample results are used in preference to age/repairs information.

The conductor is of ACSR construction and has a diameter of aluminium between 0 and 0.399% of the wire specification, which scores an EOL of 5.

There is also evidence of aluminium hydroxide on the aluminium wires of the conductor, scoring a further 5.

No other criteria are matched. The overall Secondary health score is therefore EOL 10.

12.4.3.1 OHL Fitting EoL Modifier example 1

The formula described in the methodology for EoL is given as the following. The components and details of this formula are also described.

$$EOLmod = \max(SPA, DAM, INS, PHF)$$

Equation 12.6

This circuit does not have fitting condition data. The EoL modifier is therefore driven by the preliminary score.

Some spacers on the route are missing their clamp elastomers, qualifying as score 200.

Vibration dampers are fully intact, score 0.

One defect has been logged indicating missing arcing horns on insulator fittings, scoring 400.

Some insulators show signs of corrosion, scoring 100.

EOL mod is therefore assessed to be 400 / 6 = 66. As the Preliminary score is capped at 50, the EOL modifier is set to 50. This route is clearly a high priority for level 2 inspection and/or repair work; which would likely improve the EOL modifier in future years without the need for a complete asset replacement.

12.4.3.2 OHL Fitting EoL Modifier example 2

The driver on this circuit is the phase fittings assessment. Insulator, damper, and spacers were also poor. The phase fittings are assigned a score of 600, with a large proportion of the route with sample scores of 600.

The Preliminary health score would therefore be set to 100 (600/6); and resulting EOL Modifier would be capped at 50. However, Level 2 data is available, permitting a second stage health score.

The phase fittings have been evaluated at a score of 80, with evidence of section loss on the arcing horns.

The electrical resistance of the spacer damping elements is between 0.8 & 1MOhm, resulting in a score of 70.

The porcelain insulators have eroded pins, with the diameter falling between 24.75 and 27.49mm also resulting in a score of 70.

The maximum of the component scores is therefore 80. As this is acquired from L2/L3 inspections, the score is not capped. This route would be considered an immediate priority for remedial and/or replacement action.

13 Parameters for End-of-Life Scoring

The End of Life Scoring for different asset classes uses different factors depending on what failure modes can be detected and what information is available.

Examples of asset scoring are interspersed through the previous section.

13.1 Circuit Breakers

13.1.1 General method

Circuit breakers will be assigned an end-of-life modifier according to the formula below. The maximum of the components as shown is determined, and it is capped at 100.

$$EOLmod = \max\left(AGE_{FACTOR}, DUTY_{FACTOR}, SF6_{FACTOR}, DEFECT_{FACTOR}, FAMILY_{FACTOR}\right)$$

Equation 13.1

The EoL modifier is therefore determined based on the maximum of its constituent parts. AGE_FACTOR, DUTY_FACTOR, SF6_FACTOR and FAMILY_FACTOR are non-dimensional variables with possible values between 0 and 100.

$$AGE\_FACTOR = \mathrm{C}_1 \times \mathrm{FSDP} \times \frac{\mathrm{Age}}{AAL}$$

Equation 13.2

- Age: Reporting year - Installation year (years)
- C_1: a scaling factor to convert Age to a value in the range 0 to 100. The method for calculating C_1 is described in section 14.1.7.
- *AAL* is the anticipated asset life determined through FMEA. The end-of-life curve described in the Failure Modes and Affects analysis section can be used to determine *AAL*, which is the 50% point on the respective end of life failure mode curve. The process for deriving these failure mode curves, which we use to determine AAL, are themselves estimated using historical data and engineering expertise. Further explanation is available in the section of this methodology discussing FMEA.
- FSDP is a family specific deterioration correction function described below. This is a function multiplier to convert age from a linear function to an exponential function. This has the effect of decreasing the relative significance of lower values of age.

The AAL value is determined through interpretation of historic data associated with the type and manufacturer of the circuit breaker. Other factors can also influence the AAL including locational factors such as whether the asset is indoors or outdoors. Other locational factors such as proximity to high corrosion potential are not included as these are covered through maintenance activities to ensure that the asset achieves its Anticipated Life. Note that it would require invasive work to assess the actual condition of a particular subcomponent.

13.1.2 Duty Factor

The duty of each circuit breaker asset is determined using the following formula:

$$DUTY\_FACTOR = \mathrm{C}_1 \times FSDP \times \max\left(\left(\frac{(OC)}{(MOC)}\right), \left(\frac{(FC)}{(MFC)}\right)\right)$$

Equation 13.3

Where:

OC = the current asset operational count

MOC = the expected max asset operational count over a lifetime. For older circuit breakers this is determined through liaison with suppliers, and for newer circuit breakers this is determined during type testing.

FC = the current accumulated fault current

MFC = the max permissible fault current over a lifetime. The value for MFC is set to 80% of the value of the maximum rated value for the asset.

FC and MFC are determined through liaison with suppliers who confirm operational limits for the mechanism and interrupter.

Note that the DUTY_FACTOR has been normalised to account for variations in the asset life of the circuit breaker family. This normalisation means that the end-of-life modifier of a circuit breaker from one family can be compared to the end-of-life modifier of a circuit breaker from a different family. Age and other duty related metrics are important due to the lack of more specific condition information.

13.1.3 Family Specific Deterioration Profile (FSDP)

The Family Specific Deterioration profile accounts for the expected deterioration of an asset. This is needed as there is limited availability of Asset Specific condition information. This function is based on duty value D which is given by the following formula:

$$D = \max\left(\frac{OC}{MOC}, \frac{FC}{MFC}, \frac{AGE}{AAL}\right)$$

Equation 13.4

The family specific deterioration function is determined using the function:

$$FSDP = e^{k*D^2} - 1$$

Equation 13.5

This parameter k is determined such that when D=1.0 then *FSDP*=1.0. This gives a value of k=0.694. FSDP is capped at 1.0.

This function ensures that the impact of family specific deterioration is correctly considered in the health score formula.

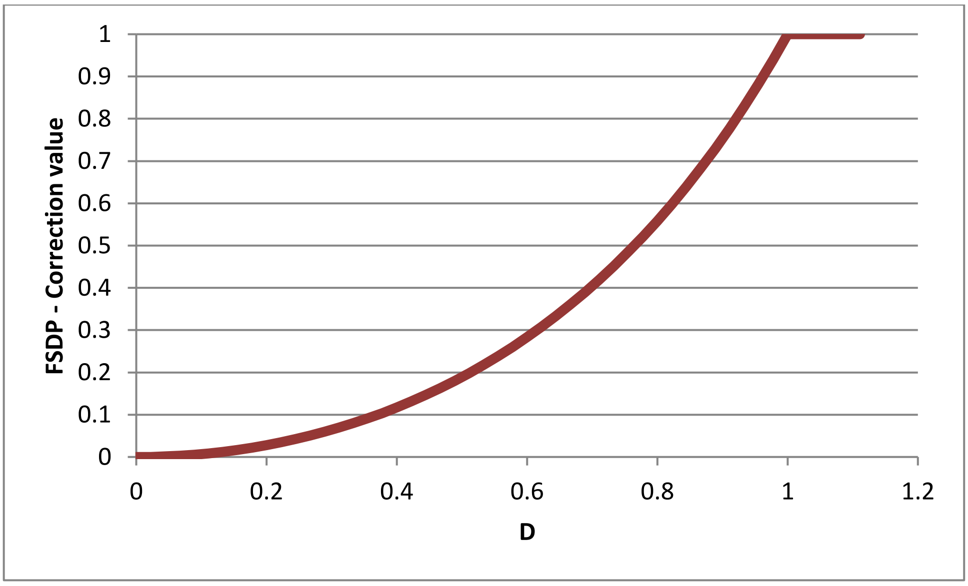


Figure 13.1

The curve will generate a value from 0 to 1 depending on the duty of the asset. This curve is used within this method due to the lack of condition information and allows us to accelerate or suppress duty values depending on the deterioration we would expect for that asset family. Note that while the shape of the curve is fixed, the duty value (D) captures family specific factors such as anticipated asset life, maximum fault current and maximum number of operations.

13.1.4 SF6 Factor

The SF6_FACTOR calculation maps the reported leakage of a circuit breaker to a score of between either 0 or 100. A score of 100 is assigned where major leakage is deemed to have occurred. Leaking time is the time in years that the asset has had a non-zero $Leak_{mass}$, $Leak_{rate}$, or $Leak_{combined}$.

$$SF6_{FACTOR} = Max(Leak_{Mass}, Leak_{Rate}, Leak_{Combined}) + Leak_{Duration} * Leaking_{time}$$

Equation 13.6

$Leak_{mass}$ is a score dependent on the mass of SF6 leakage (kg) within the previous financial year.

Mass of Leakage (kg)	**Significance**	**$Leak_{mass}$ Score**
<10kg	Insignificant	0
>=10kg	Significant	60
>=50kg	Major Leakage	75

Table 13.1

$Leak_{rate}$ a score dependent on proportion of total installed mass of SF6 that has leaked within the previous financial year.

$$Leakage\ rate = \frac{Leak_{Mass}}{Asset\ SF6\ Inventory}$$

Equation 13.7

where Asset SF6 Inventory is the Reported volume of SF6.

Mass of Leakage (kg)	**Significance**	**$Leak_{rate}$ Score**
<5%	Insignificant	0
>=5%	Significant	60
>=10%	Major Leakage	75

Table 13.8

$Leak_{combined}$=100 if both the mass of leakage is >=50kg and leakage rate is >=10%, otherwise $Leak_{combined}$=0

$Leak_{duration}$ ensures that a leaking asset for the last two or five (dependant on current severity of leak) years will be assigned a score of 100.

$$Y = Max(Leak_{Mass}, Leak_{Rate}, Leak_{Combined})$$

Equation 13.8

Leakage Duration	**$Leak_{duration}$ Score**
First year of leak	0
Y =60	8
Y =75	12.5

Table 13.9

Any asset classified with EoL modifier of 60 or 75 due to SF6 leakage will undergo a significant intervention within a 5 year or 2 year timeframe respectively. It is expected that an asset classified with a health score of 75 today will reach a health score of 100 within 2 years, which has been set-up to reflect legislation that significant SF6 leakers should be repaired within 2 years. The decision over which type of intervention to carry out, *whether that is repair, reconditioning, refurbishment, or replacement*, will be *cost justified* for the expected benefit to the consumer. This means that risk will be reduced through the most cost justified intervention, which may not necessarily be asset replacement.

Whilst there are pre-existing technologies that exist to carry out minor repairs to stop SF6 leaks, analysis of these repairs demonstrates that usually they are temporary in nature and a further major intervention is then required to permanently repair the asset.

Broadly there are two functional requirements for a Gas Circuit Breaker. Firstly, it must be able to break load, and secondly it must be able to retain the Insulating Medium. This is based on the requirements described in the Fluorinated Greenhouse Gases Regulations 2015, which places significant limits on permitted Leakage.

1. Operators of equipment that contains fluorinated greenhouse gases shall take precautions to prevent the unintentional release ('leakage') of those gases. They shall take all measures which are technically and economically feasible to minimise leakage of fluorinated greenhouse gases.
2. Where a leakage of fluorinated greenhouse gases is detected, the operators shall ensure that the equipment is repaired without undue delay. (Checking F gas equipment for leaks - GOV.UK (www.gov.uk))

13.1.5 Defect Factor
This factor is currently set to zero awaiting improved classification in data collection process.

13.1.6 Family Factor
Circuit breaker families that are exhibiting life limiting factors, which do not align to the other factors in the formulation, needs to be captured by the end-of-life modifier scoring process. As such a factor will be applied to drive intervention due to end of life to be approximately within a specific timeframe.

Asset family modifier	**Score**
Intervention within 2 years	80
Intervention within 5 years	60
Intervention within 10 years	35

Table 13.10

13.1.7 Procedure for Determining C1
This value of this parameter is determined by calculating a value for EoL modifier from historical switchgear data. The C1 value was initially tuned to give a reasonable translation between historical AHI's, which were calculated under the previous RIIO-T1 volume-based methodology, and EoL modifier. Assets that classed as AHI1 previously would be expected to have a score of 100 under the new methodology.

The scaling factors were further refined during the calibration, testing and validation exercise.

Based on this approach the parameter is fixed as $C1 = 80$

13.1.8 EoL Modifier Calculation Example

The following table shows three assets with example data that will allow us to determine the EoL modifier.

Component	Example Asset 1	Example Asset 2	Example Asset 3
Asset Operation Count (*OC*)	350	3000	350
Max Asset Operation Count (*MOC*)	5000	5000	5000
Accumulated Fault Current (*FC*)	400	400	1000
Max Permissible Fault Current (*MFC*)	1400	1400	1400
Anticipated Asset Life (*AAL*)	45	45	45
SF6 leakage (kg)	2	10	1
Age	40	20	15

Table 13.11

Applying the relevant formula presented in the above sections yields the following output.

	Example Asset 1	Example Asset 2	Example Asset 3
D (in FSDP)	0.89	0.6	0.71
FSDP	0.72	0.28	0.41
AGE_FACTOR	53.19	10.23	11.23
DUTY_FACTOR	16.73	13.94	24.16
SF6_FACTOR	0	60	0
EoL Modifier	53.2	60	24.2

Table 13.12

The EoL Modifier in example asset 1 is driven by age factor, example 2 is driven by SF6 factor and example 3 is driven by the duty factor (the accumulated fault current).

The EoL modifier calculation proposed here facilitates a reasonable translation from the AHI's utilised within the original RIIO-T1 methodology. Validation has been performed to calculate EoL modifier over a range of assets and then comparing to the AHI determined under the existing methodology.

It should be noted that placing a cap on the age-related components of health score would substantially impair the translation from the previous AHI to health score.

13.2 Transformers and Reactors

13.2.1 General method

The scoring process needs to take account of the four failure modes – dielectric, mechanical and thermal as well as issues with other components that may significantly impact the remaining service life. The end-of-life modifier is determined according to the following formula:

$$EOLmod = \left(1 - \left(1 - \frac{DCF}{100}\right)\left(1 - \frac{TCF}{100}\right)\left(1 - \frac{MCF}{100}\right)\left(1 - \frac{OCF}{100}\right)\right) * 100$$

Equation 13.9

The components of the end-of-life modifier are assigned using the scoring system described below. The component OCF (other component factor) is a factor that accounts for other issues that can affect transformer end of life. The maximum value of *EoLmod* is 100.

As far as possible National Grid uses actual condition indicators rather than extrapolating condition from load and temperature over time. This approach is more feasible with large transformers and is less dependent on the availability of historical data. The approaches are not mutually exclusive and loading data is important to the correct interpretation of some condition indicators such as oil test results.

13.2.2 Dielectric Condition Factor (DCF)

Dielectric condition is assessed using dissolved gas analysis (DGA) results. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family. Where it is known that the indications of partial discharge are coming from a fault that will not ultimately lead to failure, e.g. a loose magnetic shield, then the score may be moderated to reflect this, but the possibility of this masking other faults also needs to be considered.

Score	Dielectric Condition Criteria
0	All test results normal: no trace of acetylene; normal levels of other gases and no indication of problems from electrical tests.
2	Small trace of acetylene in main tank DGA or stray gassing as an artefact of oil type, processing, or additives. Not thought to be an indication of a problem.
10	Dormant, intermittent, or low level arcing/sparking or partial discharge fault in main tank.
35	Steady arcing/sparking or partial discharge fault in main tank. or A fault where corrective actions have arrested symptoms of the fault, but it may reoccur.
85	Indications that arcing/sparking fault is getting worse.
100	Severe arcing/sparking or partial discharge fault in main tank – likely to lead to imminent failure.

Table 13.13

13.2.2 Thermal Condition Factor (TCF)

Thermal condition is assessed using trends in DGA and levels of furans in oil. Individual Furfural concentration (FFA) results are unreliable because they can be influenced by temperature, contamination, moisture content and oil top ups, therefore a trend needs to be established over a period of time. The presence of 2 Furfural (2FAL) is usually required to validate the FFA result, and the presence or absence of methanol is now being used to validate (or otherwise) conclusions on thermal score. Thermal condition is understood to include ageing and older, more heavily used and/or poorly cooled transformers tend to have higher scores. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family.

Score	Thermal Condition Criteria
0	No signs of paper ageing including no credible furans ≥0.10ppm and methanol ≤0.05ppm.
2	Diagnostic markers exist that could indicate paper ageing (including credible furans in the range 0.10-0.50ppm) or are thought to be the result of contamination.
10	Indications or expectations that the transformer is reaching or has reached mid-life **for example**: credible furans in the range 0.51-1.00ppm or stable furans >1ppm possibly as a result of historic paper ageing. and/or DGA consistent with low temperature overheating e.g. raised levels of methane or ethane in the main tank. and/or Transformers with diagnostic markers resulting from oil contamination (e.g. furans, specifically 2FAL) that may mask signs of paper ageing.
35	Moderate paper ageing **for example**: credible furans consistently > 1ppm with a clear upward trend. and/or Significant overheating fault e.g. steadily rising trend of ethylene in main tank DGA.
85	Transformer is aged and believed to be within the final quarter of its life which may be evidenced by advanced paper ageing, **for example**: • Credible furans > 1.5ppm showing a clear upward trend (even if the furan level has subsequently stabilised) or where the paper could be expected to be aged (DP:~250) based on indications from a previously scrapped sister unit which may be supported by the presence of methanol. and/or Significant and worsening overheating fault.
90	Transformer is believed to be within 5-10 years of its end of life which may be evidenced by very advanced paper ageing, **for example**: • Credible furans ~2.0ppm showing a clear upward trend (even if the furan level has subsequently stabilised) or where the paper could be expected to be significantly aged (DP:~240) based on indications from a previously scrapped sister unit. • Or similarly credible furans ~1.5ppm in a transformer with <40 service years (indicating premature ageing) • Indications of methanol and/or Significant and worsening overheating fault.
95	Transformer is believed to be within 5 years of its end of life which may be evidenced by severe paper ageing, **for example**: • Credible furans > 2ppm showing a clear upward trend (even if the furan level has subsequently stabilised) or where the paper could be expected to be severely aged (DP:~220) based on indications from a previously scrapped sister unit. • Indications of methanol. and/or Significant and worsening overheating fault.
100	Paper aged to end of life, **for example**: credible furans >2.25ppm with an upward trend or where a sister unit was found to be at end of life (DP<200) with similar indications when scrapped. and/or Serious overheating fault.

Table 13.14

Electrical test data may be used to support a higher thermal score where they show poor insulation condition. Electrical tests can provide further evidence to support the asset management plan for individual transformers e.g. where a significant number of oil tops ups have been required for a particularly leaky transformer and it is suspected that this is diluting the detectable Furans in the oil. However experience shows that not all poor thermal conditions can be detected by electrical tests which is why DGA data remains the focus for scoring the Thermal Condition Factor.

While age and AAL are not explicitly considered as part of the transformer EoL modifier scoring process, the thermal condition score is a fairly good indicator of the age of an asset. The DGA results obtained from oil samples will generally show signs indicating the aging of a transformer including increased levels of furans.

13.2.3 Mechanical Condition Factor (MCF)

Mechanical condition is assessed using Frequency Response Analysis (FRA) results.

Score	Mechanical Condition Criteria
0	No known problems following testing.
1	No information available.
3	Anomalous FRA results at last measurement which are suspected to be a measurement problem and not an indication of mechanical damage. and/or Corrected loose clamping which may reoccur.
10	Loose clamping or Following the indications of a sister unit found to have had compromised mechanical integrity/short circuit strength. or A design known to have a poor short circuit design.
35	Suspected mechanical damage to windings. This does not include cases where the damage is confirmed.
85	Loose or damaged clamping likely to undermine the short circuit withstand strength of the transformer.
100	Confirmed mechanical damage to windings.

Table 13.15

Mechanical condition is assessed using Frequency Response Analysis (FRA) results; FRA is used to detect movement in the windings of the transformer, these data are supplemented by family history e.g. where postmortem analysis of a similar transformer has confirmed winding movement and DGA results (which indicate gas generation from loose clamping) as appropriate.

13.2.4 Other Condition Factor (OCF)

The Other Components score uses an assessment of other aspects; this includes:

- Tap-changers. Tap-changers are maintained and repaired separately to the transformer and defects are most likely repairable therefore tap-changer condition does not normally contribute to the AHI score. Where there is a serious defect in the tap-changer, and it cannot be economically repaired or replaced this will be captured here.
- Oil Leaks. During the condition assessment process transformers may be found to be in a poor external condition (e.g. severe oil leaks), this will be noted, and the defect dealt with as part of the Asset Health process. The severity of oil leaks can be verified by oil top up data. Where there is a serious defect and it cannot be economically repaired, this will be captured here.

Other conditions such as tank corrosion, excessive vibration that cannot be economically repaired and audible noise which has resulted in complaints from stakeholders will be captured here.

Score	Other Component Criteria
0	No known problems/minor or infrequent oil leaks.
2	Oil leaks (in excess of 2000 litres per annum over the past 3 years) that **can** be economically repaired but the volume of top ups may be diluting diagnostic gases.
10	Oil leaks (in excess of 2000 litres per annum over the past 3 years) that cannot be economically repaired. and/or Tap-changer that is known to be obsolete and spare parts are difficult to acquire or that is heavily used(average operations >6500 p.a.)/incurs high maintenance costs. Or, based on historic failure data, the tap-changer is known to have a higher risk of failure.
35	Exceptional oil leaks (on a rolling basis, generally in excess of 10 000 litres per annum over the past 3 years) that cannot be economically repaired where the annual oil top up volume is likely to be diluting diagnostic markers. and/or Other mechanical aspects potentially affecting operation that cannot be economically repaired for example: tank corrosion, excessive vibration. or Justifiable noise complaint for which there may be a practicable means of mitigation.
85	Exceptional oil leaks (on a rolling basis, generally in excess of 15 000 litres per annum over the past 3 years) that cannot be economically repaired and where the effectiveness of the secondary oil containment system is in doubt and would be difficult or impossible to repair without removing the transformer. and/or Tap-changer that is known to be in poor condition and obsolete with no spare parts available. or Justifiable noise complaint for which there is no practicable means of mitigation, where empirical data supports the noise complaint and there is a strong indication that a noise abatement notice could be served.
100	Confirmed serious defect in the tap-changer that cannot be economically repaired or replaced. or Audible noise complaint which has resulted in a noise abatement notice, for which there is no practicable means of mitigation.

Table 13.16

Where noise mitigation measures are planned the Other Component Score may be subject to review, for instance where efficiencies can be delivered by bringing forward a planned replacement and negating the need to take mitigating actions.

Oil quality is assessed using the results of four tests – acidity, interfacial tension, dissipation factor and resistivity. The oil quality score does not contribute to the AHI score, but it is used to prioritise transformers requiring oil replacement or regeneration.

13.2.5 Family Specific Considerations

Where individual test results, trends in test results or family history give cause for concern, specialist diagnostics are scheduled as part of a detailed condition assessment. Where appropriate, continuous monitoring will also be used to determine or manage the condition of the transformer. The EoL modifier scoring process will then be applied as described above, which can lead to an increase in the score applied to an asset.

Thermal condition is assessed using trends in DGA and levels of furans in oil, supplemented by family and operational history and electrical test data as appropriate. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family. Following the scrapping of a transformer it may be necessary to review the thermal scores assigned to remaining sisters in a family.

Note that transformers share the same end of life failure mode group. Reactors are split into two end of life failure mode groups. A failure mode group has specific parameters for earliest and latest onset of failure ages. The process for deriving these failure mode curves, are themselves estimated using historical data and expert opinion. Further explanation is available in the section of this methodology discussing FMEA.

13.3 Cables

13.3.1 General method

As noted in section 13, this issue of the NARA introduces an improved method to a Cable Scoring method for RIIO-T3.

The formula to determine the EoL modifier for cables, which is capped at a maximum of 100, is:

$$EOLmod = ACS + CCS$$

Equation 13.10

Where
CCS = Cable Condition Score
ACS = Accessories Condition Score [n.b. in the previous issue of NARA, the acronym ACS had different meaning].

CCS = AALc * GFR + max (DEFECTS, PRDEFECTS) + COST + ACCESS + max (OIL, PROIL) + Main_adj

Equation 13.11

And
ACS = Sum of scores contributed from accessories (link boxes, stop joints, SVL's, joint plumbs, oil systems & cooling systems).

The factors defined in this formula are described as listed below.

13.3.2 Current Age Variation from Anticipated Asset Life (AALc)

In the table below variation= age – anticipated asset life. The anticipated asset life is listed in the appendix section and reflects specific issues associated with a particular family. As noted in section 13, the AALc and GFR previously contributed to the majority of a cable scoring. The AALc and GFR are not measures of individual asset condition, but can be applied to understand the portfolio of assets. The extent of the contribution from AALc and GFR have therefore been scaled back in the scoring mechanism.

Variation from anticipated asset life (*AALC*)	
>=Variation	Score
-10	5
0	8
5	10
10	15

Table 13.17

13.3.3 Generic Family Reliability (GFR)

This component is used to score any known generic family issues which can affect the anticipated life of the asset, that is, a design weakness may become apparent for a particular family of assets. For example, it has been determined that type 3 cables have a known generic defect. Type 3 cables are AEI and pre-1973 BICC oil filled cables with lead sheath and polyvinyl chloride (PVC) over sheath and an additional risk of tape corrosion or sheath failure. This scoring takes account of the family design issues which are a risk to the anticipated asset life.

These values have been selected to retain their significance, but not domineer a cables CCS score. If there are no defects apparent, and the failure mechanism is not active, then the condition score should not be pressing for a cable to be replaced, as it is not exhibiting defects. But, where there are issues, the profile of these risks will be raised.

Generic Family Reliability (*GFR*)	
	Weighting
Evidence of design issue	2
Vulnerable to design issue	1.5
Vulnerability to design issue mitigated	1
All Others	1

Table 13.18

13.3.5 Defects & Pro-rated Defects.

This is evaluated as the rolling count of 10-years of defects raised against per asset. The scoring mechanism has been updated to create a more graduated response to count of defects, rather than risk of step changes.

Note that this approach does mean that cables can still appear to improve over time, depending on the nature and timing of defects encountered.

Number of Defects (DEFECTS)	
>= Number of Defects	Score
0	0
3	6
5	10
10	20
20	40
30	60

Table 13.19

A new feature of this mechanism is also to calculate PRDEFECTS, that is, pro-rata calculation of number of defects per unit length. This is a similar mechanic to the PROIL calculation; noting that a short cable has less to go wrong than a longer route. This is included to control a potential bias towards longer circuits. The primary use for this component is to assess non-Transmission cables (therefore cables not treated under the NARM mechanism) such as the short lengths (circa 300m) often found in substations.

Pro-rated Defects (PRDEFECTS)	
No. Defects per km	Score
>100	40
>50	30
>20	20
<20	0

Table 13.20

13.3.6 Cost

The cost metric replaces the 'defect severity' metric in previous issues of the NARA. It is a measure of expenditure on a circuit over time. Cable repair work is specialised in nature and mostly completed by third parties on behalf of NGET within a commercial framework known as the CCMR. The cost of this work is important for two reasons:

1) Expenditure infers that meaningful issues are being detected requiring rectification.
2) High expenditure over time is a strong reason in of itself to consider an alternative.

Detailed CCMR data is available from 2016 onwards. It does not represent all historical costs; it rather, covers for work above and beyond routine expenditure associated with the existence of the cable.

Total CCMR Expenditure (COST)	
CCMR Cost (£)	Score
<50,000	0
50,000-100,000	5
100,000-250,000	10
250,000-500,000	20
500,000-1,000,000	30
1,000,000+	40

Table 13.21

13.3.7 Average Circuit Unreliability (ACU)

In the previous NARA, the “ACCESS” scoring component was used as a measure of performance. The implementation of this method, did not facilitate asset replacement decision making. For example, in 2021/2022, 14 cables registered sufficient downtime to score according to the NARA-T2 methodology. On inspection, these outages were not associated with cable defects and repairs; rather, with other equipment and events on affected routes.

An Average Circuit Unreliability (ACU) metric is a useful alternative to a downtime measure.

This issue of the NARA therefore modifies this scoring parameter to only consider outages taken due to cable condition contributions to downtime. Factors associated with ACU remain high, noting that significant downtime calls into question the utility of a given cable system.

ACU	
Time	Score
<2 weeks	0
2-4 weeks	5
4-8 weeks	10
8-16 weeks	20
16+ weeks	30

Table 13.22

13.3.8 Historical Oil leaks in Last 10 Years (Oil)

This table has been updated to reflect NGET's environmental ambitions. The sum of oil leaked in the last 10 years is used.

Oil leaks last ten years (*OIL*)	
>= Litres	Score
<100	5
100	10
500	20
2000	30
10000	40

Table 13.23

13.3.9 Pro-Rate to 1km Oil Leaks in Last 10 Years (PROIL)

In order to account for oil leaks from short lengths of cable, the quantity of oil lost over the last 10 years is divided by the length of the cable in order to ensure that the relatively low quantity of oil in a short cable is not overlooked for attention.

Oil leaks last ten years (*PROIL*)	
>= Litres/km	Score
<100	5
100	10
500	20
2000	30
10000	40

Table 13.24

13.3.10 Main Cable Information (MAIN_ADJ)

The following condition scores will be applied when determining a cable EoL score.

These factors tend to be bespoke to each cable route and are assessed individually as required by evidence.

Laying Environment score, in a range 5-40. The range is large to accommodate for critical end-of-life factors that can arise as a result of geophysical issues such as subsidence.

Sheath faults, in the range 5-20. Sheath faults are routinely tested as part of maintenance activities and rectified through defect management. That said, the repeated occurrence of sheath defects implies lifetime-limiting issues with the conductor (be that due to faults, downtime, etc.)

Known Bronze Tape Corrosion, in the range 5-20. Certain older fluid-filled cables are known to have a propensity towards corrosion of their reinforcing tapes; the failure of which can lead to loss of oil, water ingress, and complete failure of the cable. Where evidence exists of failures caused by corrosion, scores are modified accordingly. Most of these types of cable will have been disposed by the beginning of the next price control, though a handful of examples are still operating.

In a manner similar to the Scottish TO's NARA's, we have for this issue introduced an "Scoring at discretion" field. This provides a placeholder for any other issues bespoke to cable assessments not covered by other criteria. Where the discretionary score has material impact on investment decisions, appropriate justification must accompany their use.

13.3.11 Accessory Condition Scoring (ACS)

Cable accessories are components other than that of the cable conductor. The cable cannot function without adequately performing accessories. Scoring for these parameters have been expanded to the range 5-20.

It is entirely probable that cable conductors can and will outlive their accessories. The viability of a refurbishment or replacement is not determined through the NARM mechanism, but both interventions are valid if highlighted the cable has high risk through the calculation of monetised risk.

The range on these parameters has been increased in order to provide better visibility of factors arising from accessory components. The replacement of oil systems, for example, is a non-trivial task and there are strong environmental and reliability concerns were such an item to fail.

Factors considered as part of the ACS include:

- History, or Risk of failure of older models of link boxes.
- History, or Risk of stop joint failure.
- History, or Risk of sheath voltage limiter (SVL) failure.
- History, or Risk associated with joint plumb condition.
- History, or Risks associated with oil tanks, oil lines, pressure gauges and alarms.
- History, or Risks associated with cooling systems (if present).

13.4 Overhead Line Parameters

13.4.1 General method

Each asset within the overhead line system may be understood in terms of the functions they perform, and each of the ways in which they can fail to perform those functions. The effects of the failure modes, their underlying causes, and ways in which they might be detected before they occur are the key points of understanding. For NARM purposes, NGET calculates separate scores for Conductor and Fitting Systems

Each failure mode has some probability of occurrence over time. This may change with continual and periodic degradation of the asset as it responds to the operating environment and continued use.

Both OHL conductors and fittings undergo two-stage scoring processes. Preliminary and level 1 evaluation are based upon asset family knowledge and visual surveying.

The second stage is reliant upon condition data and forensics. Evidence is subdivided into three levels. The availability of data dictates which scoring approach is used.

Higher levels supersede lower levels where available.

For both conductors and fittings, data acquired at levels 2 and 3 are considered valid for a maximum of 10 years.

Scoring assessments are made on sections of circuit that are typically homogenous in conductor type, installation date and environment. Where a given route spans multiple environments, there are implications for the location of and number of samples required to infer the condition of the wider route.

Level 1 condition assessment is a visual screening technique using high-definition cameras mounted on helicopters or drones. This assessment is also applicable to Spacers, Vibration Dampers, Insulators, Fittings with each component type scored by phase.

Outputs from these assessments will be used to inform the selection of candidates for level 2 condition assessment.

Level 2 Outage condition assessment requires system access for close inspection and measurement of insulators & fittings showing signs of wear. Most of this type of inspection can be completed in situ, though it is possible to take advantage of outages to take samples where necessary.

Level 2 inspection techniques include:

- Measurement of dimensions of linkages, insulator connections and landing pins
- Resistance measurement of insulators (porcelain only)
- Removal of conductor samples for forensic analysis
- Removal of fittings or insulators for forensic testing
- Resistance readings of compression and bolted conductor clamps.

Note at this time procedures for HTLS (High temperature low sag conductor) are still to be developed to enable inspection of short sections similar to those carried out on other conductor types.

Level 3 condition assessment requires the forensic inspection and testing of components removed from service. The forensic inspection will typically be completed by 3rd party laboratories.

Level 3 inspections include:

- Conductor sampling. The sample will be removed from a single conductor in a bundle. Ideally, samples are taken to offer two forensic opportunities, the first at a clamping position (spacer, damper, or suspension clamp) and the second at an adjacent unclamped position.
- Insulators. Would normally only be removed following a failure but can be removed where a comprehensive assessment is necessary.
- Vibration dampers. Removal of all dampers from a single phase in a span.

13.4.2 OHL Conductors General method

Overhead Line Conductors are assigned an end-of-life modifier using a 2-stage calculation process. The maximum value of *EoLmod* is 100.

All conductors are evaluated for their preliminary health score. The preliminary health score is capped at 40.

If validity criteria for forensic data collection are met, then the second stage health score supersedes the preliminary health score.

$$EOLmod = \begin{cases} PRE_{HS} & if\ VAL = 0 \\ SEC_{HS} & if\ VAL = 1 \end{cases}$$

Where:
PRE_{HS} is the Preliminary score
SEC_{HS} is the Secondary score
VAL is the Validity Criteria flag

To ensure that condition data is indicative of the whole circuit being assessed, a validity check is applied. All environment categories the circuit passes through must be assessed and at least one conductor sample per 50km is required.

VAL = Criteria A * Criteria B

Where:

Validity Criteria A	***Criteria A value***
No. of Categories Assessed / No. of Environment Categories= 1	1
No. of Categories Assessed / No. of Environment Categories <1	0
Validity Criteria B	***Criteria B value***
No. of samples per 50 route km >=0.02	1
No. of samples per 50 route km <0.02	0

Table 13.25

13.4.2.1 Preliminary Stage

Each conductor is assigned to a ‘family’ which has an associated asset life.

The three major families are

- Aluminium Conductor Steel Reinforced (ACSR) conductors
- All Aluminium Alloy Conductor (AAAC) & Aluminium Conductor Alloy Reinforced (ACAR) conductors
- High Temperature Low Sag (HTLS) conductors.

Each span on an overhead line route is categorised for wear and corrosion data. The process of wear and fatigue over the lifetime of a conductor can reduce wire cross section, ductility, and strength. Wind and wear categories are important in the process of determining the remaining Rated Tensile Strength (RTS) for each family of OHL conductors. Each conductor family is rated for family performance over time relative to the whole network.

There may be more than one environmental category per route; where this is the case, the most onerous category is assumed.

The Preliminary end of life modifier is taken to be the maximum of a hot joint or repair-based score, multiplied by a family weighting based on condition assessment of that family. The PRE_{HS} score is necessarily based on factors such as family weighting, defect and repair history, as these are the most complete data sets available.

$$PRE_{HS} = W_{FAM} * \max(JNT_{SCORE}, REPAIR_{SCORE})$$

Equation 13.12

Where W_{FAM} = Average Sample Score within Family / Average Sample Score across all conductor assets
And $REPAIR_{SCORE}$ = Number of Conductor Repairs being assessed divided by the number of spans within the given route * 100

JNT_{SCORE} follows the following table:

Infrared survey outcomes	Score
Hot Joints in Main Compression element of joint > 2.5% on all tension compression components in the last 5 years	10
Hot Joints in the compressed element of a jumper palm > 2.5% of tension and terminal towers in the last 5 years	7.5
Hot joints in the bolted interface of a jumper palm >2.5% of tension and terminal towers in the last 5 years	5

Table 13.26

W_{FAM} is a family weighting score derived from OHL conductor sample data. The aim of this is to enhance PRE_{HS} as a proxy for asset condition in the absence of sample data coming from a specific route.

The ability to detect the condition state of a conductor is limited. Conductors are composite and linear assets; where the condition state is hidden information unless forensic analysis is carried out.

Hot joint instances (JNT) can usually be rectified by splitting, cleaning, and reassembling the offending joint. This option is not always available or can be difficult to complete where an OHL anchor clamp and jumper compression joint are integral to each other, in which case, the joint will need to be shunted or removed & replaced using an approved repair technique. This type of defect does not necessarily mean the end of life for an asset however they are an indicator that the occurrence of further hot joints can be expected to increase in the short to medium term.

If the number of repairs on a given route is high, it should be subject to further investigation regardless of condition of the other components on the asset. The spread of repair locations is also significant, clusters may appear in spans with local environmental characteristics (e.g. aeolian activity or pollution). The damping or configuration of the bundle within the affected spans may require intervention to prevent early failure of the route.

The length of time in service of the asset within specific environments is important to the planning of conductor forensics, however, it does not form part of secondary scoring. Conductor assets will not normally be subject to intrusive sampling until at least 50% of the asset's anticipated lifetime has been reached.

13.4.2.2 Second Stage Conductor Score

On completion of the preliminary scoring, further condition assessment may be undertaken to allow a second stage assessment of a conductor.

$$SEC_{HS} = Mean\ of\ Maximum\ \&\ Mean\ scores\ of\ all\ phase\ conductor\ samples$$

Equation 13.13

Intrusive assessments are required to permit the second stage assessment of a given route. To obtain conductor data indicative of a long route, a validity criterion is applied. All environment categories passed through must be assessed. Where more than one sample exists for a particular environment, the higher of the scores is used in this assessment.

Removal of a conductor sample for analysis can be done midspan locations, though spacer clamp attachment points. The removal of 760mm long pieces of conductor from an in-span location offers the opportunity to complete two forensic examinations, one of the unclamped areas, the other where a spacer clamp has been attached to the conductor.

There are instances where a conductor is known to be in an area of high aeolian activity or does not have spacers installed. In cases such as this, the preferred option is to remove a longer sample through a suspension point.

Forensic scoring criteria for ACSR, AAAC and ACAR have been developed. There are currently no scoring criteria for HTLS conductors. When applying scoring criteria, the sum of all component scores are considered for each given sample.

Results of the secondary health score are only considered if the criterion for a valid set of condition assessments as described above is met. Tables describing the conductor scoring criteria follow:

ACSR - Level 3 Scoring Criteria

Diameter of Aluminium Wires **Lynx – 2.79mm Zebra - 3.18mm**	
Greater than 0.4% below the minimum wire specification	10
Between 0 and 0.399% below the minimum wire specification	5
Equal to or above the minimum wire specification	0
Diameter of Steel Wires **Lynx – 2.79mm Zebra - 3.18mm**	
Greater than 0.4% below the minimum wire specification	10
Between 0 and 0.399% (inclusive) of the minimum wire specification	5
Equal to or above the minimum wire specification	0
Average Electrical Resistance of Aluminium Wires	
Equal to or greater than 10% higher than 28.26nμΩ/m	10
Between 5.1 & 9.9% higher than 28.26nμΩ/m	7.5
Between 0.1 & 5% higher than 28.26nμΩ/m	5
Equal to or less than 28.26nμΩ/m	0
Average Tensile Breaking Load of Aluminium Wires **Lynx – 1030N Zebra – 1310N**	
Equal to or greater than 15% loss of strength of aluminium strands	15
Between 10.1 & 14.9% loss of strength of aluminium strands	10
Up to 10% loss of strength of aluminium strands	5
Equal to or greater than 100% of strength of aluminium strands	0
Average Tensile Breaking Load of Steel Wires **Lynx – 6970N Zebra – 8740N**	
Greater than or equal to 15% loss of strength of steel strands	15
Between 10.1 & 14.9% loss of strength of steel strands	10
Up to 10% loss of strength of steel strands	5
Equal to or greater than 100% of strength of steel strands	0
Aluminium Wire Wrap Tests	
Less than 11 turns to failure	15
Between 11 & 17 turns to failure	10
Between 18 & 24 turns to failure	5

Equal to or greater than 24 wraps to failure	0
Steel Wire Torsion Tests	
Less than 6 revolutions to failure	15
Between 6 & 10 revolutions to failure	10
Between 11 & 13 revolutions to failure	5
Equal to or greater than 14 revolutions to failure	0
Grease Condition	
Hardened	5
Discoloured & Pliable	2
Golden & Pliable	0
Presence of Aluminium Hydroxide on conductor	
Yes	5
No	0

AAAC & ACAR - Level 3 Scoring Criteria

Diameter of Aluminium Alloy Wires **Upas – 3.53mm** **Totara – 4.14mm** **Collybia – 3.37mm** **Rubus 3.50mm** **Sorbus – 3.71mm** **Araucaria – 4.14mm** **Redwood - 4.56mm**	
Greater than 0.4% below the minimum wire specification	10
Between 0 and 0.399% (inclusive) of the minimum wire specification	5
Equal to or above the minimum wire specification	0
Average Electrical Resistance of Aluminium Alloy Wires	
Equal to or greater than 10% higher than 31.50nμΩ/m	10
Between 5.1 & 9.9% higher than 31.50nμΩ/m	7.5
Between 0.1 & 5% higher than 31.50nμΩ/m	5
Equal to or less than 31.50nμΩ/m	0
Average Tensile Breaking Load of Aluminium Alloy Wires **Upas, Collybia & Rubus 165Mpa** **Sorbus, Totara Araucaria & Redwood 160Mpa**	
Greater than or equal to 15% loss of strength of aluminium alloy strands	15
Between 10.1 & 14.9% loss of strength of aluminium alloy strands	10
Up to 10% loss of strength of aluminium alloy strands	5
Equal to or greater than 100% of strength of aluminium alloy strands	0
Aluminium Alloy Wire Wrap Tests	
Less than 4 revolutions to failure	15
Between 4 & 7 revolutions to failure	10
Equal to or greater than 8 revolutions to failure	0
Grease Condition	
Hardened	5
Discoloured & Pliable	2
Golden & Pliable	0
Presence of Aluminium Hydroxide on conductor	
Yes	5
No	0

13.4.3 General Method for OHL Fittings

Overhead Line Fittings are assigned an EoL modifier using a 2 stage calculation process. EOL Modifier is capped at a maximum of 100.

All fittings are evaluated for their preliminary health score. The preliminary health score is capped at 70.

OHL Condition assessments are calculated for four possible levels of asset intelligence, Preliminary, level 1, 2 and 3 scores.

For insulators and phase fittings, level 2 and 3 scores may both exist. Where they do, the maximum score is used.

In all other cases, provided a sufficiently representative sample of data is available at that level; that level of score supersedes lower levels of scoring.

The overall EOL modifier for fittings is calculated by four component types – spacers, dampers, insulators and phase fittings. Generically, whichever level of assessment is applied, the EOLModifier is classified by the worst scoring component within a given routelet.

Where a component does not exist (e.g. spacers on a single conductor OHL) the score is automatically set to zero.

EOLMod = max (SPA, DAM, INS, PHF). [Scoring components for Spacers, Dampers, Insulators & Phase fittings]

Preliminary score calculation

For each preliminary scoring component (SPA, DAM, INS, PHF) calculate "A", where A = Assessment Year – Installation Year – AAL.

e.g. $EOL_{SPA\ PS}$ = Prelim Score [PS] * Environment Modifier

If A is <= -13 then P = 0
If A is > -13 and < -3 then PS = 300/6
If A > -3 then PS = ((A*30)+390)/6

E.g. if A = -3, then PS = ((-3*30)+390)/6 = 50.

Level 1 calculation

Level 1 scores are graded on a scale of 100 to 600; which are later converted back to an EOL modifier on the scale 0-100.

For each level 1 scoring component (SPA, DAM, INS, PHF), the level 1 preliminary score is determined by assessment of all spans in a given routelet. The score applied is the maximum of:

a) Where 50% or more assets score at a particular level or higher
b) The maximum single-span score for any route that is 4.5km or greater length.

For example, say Level 1 scoring for a particular routelet's spacers is per the following:

Score	100	200	300	400	500	600
No. Spans	6	50	170	0	5	8

More than 50% of the spans score 300 or higher, therefore a Level 1 score of 300 applies.

Next, each Level 1 preliminary score is subject to an environmental modifier. Level 2 and 3 scores are not, as the latter are based upon direct measurement of condition.

EOL $EOL_{SPA\ L1}$ = (L1 score * Env. Modifier) / 6.

In this example, EOL SPA L1 = (300*1.1)/6 =55 (rounded to nearest integer).

<u>Level 2 calculation</u>

Level 2 scoring is applied to Insulators and Phase Fittings only, per the L2 tables given below.

$EOL_{INS\ L2}$ = sum (level 2 component scores).

Note that the score is capped at a maximum of 100, anything > 100 = 100.

<u>Level 3 calculation</u>

Level 3 applies to Spacers and Dampers only, per the L3 tables given below.

EOLSPA L3 = sum (level 3 component scores).

Note that the score is capped at a maximum of 100, anything > 100 = 100.

Concerning the Level 1 scoring, note that defects that score 400 or 500 within their respective criteria are typically "surface visible" defects. Depending on the proportion of a route in that state, and necessary timing for intervention; they may be flagged for management under defect processes rather than for asset replacement. The objective here is to avoid a single bad fitting requiring attention to flag an entire route for replacement, which would clearly be inefficient. This does not preclude the need to conduct the defect repair work.

The Level 2 and 3 criteria require detailed inspection of assets. It would not be realistic or cost effective to collect this level of detail for every span. Where is can be collected, this information aids in classification of asset health scores; and provides cross-validation of the Level 1 scoring. A route is evaluated for the applicability of Level 2 and 3 scoring according to the given criteria; and to whether it is a representative sample..

The environmental modifier used in preliminary and level 1 scoring differentiates assets that receive a higher challenge from their operating environment. These are applied to each subcomponent score.

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

where:

Environment Modifier	Description
A	Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant.
B	Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source
C	No Pollution – Rural areas at least 15km from the coast
D	Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems

Level 1, 2 and 3 fittings scoring criteria follow:

LEVEL 1 FITTINGS INSPECTION SCORING CRITERIA

		Level 1 Visual Assessment				
	Phase and Jumper Spacers	Good Condition	Dull Appearance	Black Appearance	Slight Oxidation Deposits Around Conductor Clamp and Locking Pins	Severe Oxidation Deposits Around Conductor Clamp and Locking Pins
Level 1 Visual Assessment	Tight and Secure	100	200	300	400	500
	Locking Pins Ineffective or Loose	600	600	600	600	600
	Rubber Missing	600	600	600	600	600
	Loose Arms	600	600	600	600	600
	Clamps Loose	600	600	600	600	600
	Clamps Open	600	600	600	600	600
	Missing	600	600	600	600	600

		Level 1 Visual Assessment				Trigger for Level 2 Measurements
	Insulator	Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust on Bells, Majority of Galvanised Coating Missing	Heavy Rust on Bells	Bells Severely Corroded and Some Section Loss to Pins <10% for 190kN <2.5% for 300kN
Level 1 Visual Assessment	No Pollution	100	200	200	300	300
	Evidence of Light Pollution	200	300	300	300	400
	Evidence of Heavy Pollution	300	300	300	300	400
	Visible Burn Marks, Glass Erosion	400	400	500	500	500
Level 2 Trigger	Evidence of Crazing/ Cracking	600	600	600	600	600

	Arcing Horn/ Corona Ring	Level 1 Visual Assessment: Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust, Majority of Galvanised Coating Missing	Heavy Rust	Heavy Corrosion, Pitting of Steelwork and Some Section Loss
Level 1 Visual Assessment	Tight and Secure	100	200	300	400	500
	Missing Components, Locking Nuts etc	300	400	400	400	500
	Loose	400	400	500	500	500
	Missing	600	600	600	600	600
	Incorrect Length	600	600	600	600	600

	Dowel Pin/ Bolts/ Washers and Split Pins **Phase and Earthwire Linkages (Suspension & Tension)**	Level 1 Visual Assessment: Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust, Majority of Galvanised Coating Missing	Heavy Rust	Heavy Corrosion, Pitting of Steelwork and Some Section Loss
Level 1 Visual Assessment	Minimal Wear 0-10%	100	200	300	300	400
	Slight Wear 10-20%	200	300	300	400	500
	Moderate Wear 20-40%	300	300	400	500	500
	Heavy Wear 40-60%	400	400	500	600	600
	Severe Wear >60%	600	600	600	600	600
	Missing/ Out of Plumb >20^0/ Cracked Wedge Clamp	600	600	600	600	600

Level 1 Visual Assessment	Phase and Jumper Spacers	Level 1 Visual Assessment: Good Condition	Dull Appearance	Black Appearance	Slight Oxidation Deposits Around Conductor Clamp and Locking Pins	Severe Oxidation Deposits Around Conductor Clamp and Locking Pins
	Tight and Secure	100	200	300	400	500
	Locking Pins Ineffective or Loose	600	600	600	600	600
	Rubber Missing	600	600	600	600	600
	Loose Arms	600	600	600	600	600
	Clamps Loose	600	600	600	600	600
	Clamps Open	600	600	600	600	600
	Missing	600	600	600	600	600

Level 1 Visual Assessment	Phase and Earthwire Dampers	Level 1 Visual Assessment: Galvanising Weathered, Dull Appearance	Galvanised Coating Starting to Deteriorate	Light Rust, Majority of Galvanised Coating Missing	Heavy Rust	Heavy Corrosion, Pitting of Steelwork and Some Section Loss
	0-20° Droop	100	100	200	200	300
	20°-40° Droop	100	100	200	300	400
	40° + Droop	600	600	600	600	600
	Bell(s) missing, messenger wire broken or slipped	600	600	600	600	600
	Slipped	600	600	600	600	600
	Missing	600	600	600	600	600

Level 1 Visual Assessment	Earth Bond	Level 1 Visual Assessment: Protective Coating Intact	Protective Coating Starting to Split/Crack. Conductor Intact	Protective Coating Starting to Split/Crack. Broken Strands Visible.	Protective Coating Totally Ineffective. Majority of Conductor is Broken
	Tight and Secure	200	300	400	500
	Incorrectly Fitted	600	600	600	600
	Connections Loose	600	600	600	600
	Earths or conductor clamps not connected	600	600	600	600
	Broken	600	600	600	600
	Missing	600	600	600	600

LEVEL 2 & 3 INSPECTION SCORING CRITERIA

Elastomer Lined Clamp Spacer Damper Level 3 Scoring Criteria (Triple & Quad)

Electrical Resistance of Elastomeric Damping Elements	
The electrical resistance of damping elements below 0.8MΩ or above 24MΩ	15
The electrical resistance of damping elements is between 0.8 & 1MΩ or between 20 & 24MΩ	10
The electrical resistance of damping elements is between 1MΩ & 20MΩ	0
Electrical Resistance of Elastomeric Clamp Liners	
The electrical resistance of clamp liners below 0.8MΩ or above 24MΩ	15
The electrical resistance of clamp liners is between 0.8 & 1MΩ or between 20 & 24MΩ	10
The electrical resistance of clamp liners is between 1 & 20MΩ	0
Longitudinal Clamp Slip	
The spacer clamps slipped at or below 2.5kN	10
The spacer clamps slipped between 2.5 & 3.95kN	5
The spacer clamps withstood a slip load of 5kN	0
Damping and Elastic Properties (Stiffness)	
Spacer demonstrates stiffness test results below 6.0° & above 16.5°	30
The spacer demonstrates stiffness results between 6 & 7.5° or 15 & 16.5°	15
Spacer demonstrates stiffness test results between 7.5 & 15°	0
Damping and Elastic Properties (Log Decrement)	
Spacer demonstrates a Log Dec result lower than 0.72	30
Spacer demonstrates a Log Dec result between 0.72 & 0.899	15
Spacer demonstrates a Log Dec result of 0.90 or higher	0

Elastomer Lined Clamp Spacer Damper Level 3 Scoring Criteria (Twin)

Electrical Resistance of Elastomeric Damping Elements	
The electrical resistance of damping elements below 0.8MΩ or above 24MΩ	15
The electrical resistance of damping elements is between 0.8 & 1MΩ or between 20 & 24MΩ	10
The electrical resistance of damping elements is between 1MΩ & 20MΩ	0
Electrical Resistance of Elastomeric Clamp Liners	
The electrical resistance of clamp liners below 0.8MΩ or above 24MΩ	15
The electrical resistance of clamp liners is between 0.8 & 1MΩ or between 20 & 24MΩ	10
The electrical resistance of clamp liners is between 1 & 20MΩ	0
Longitudinal Clamp Slip	
The spacer clamps slipped at or below 2.5kN	10
The spacer clamps slipped between 2.5 & 3.95kN	5
The spacer clamps withstood a slip load of 5kN	0
Damping and Elastic Properties (Stiffness)	
The spacer demonstrates stiffness test results below 2.5 or above 7N/mm	30
The spacer demonstrates stiffness test results between 2.5 & 3.5N/mm or between 6 & 7N/mm	15
The spacer demonstrates stiffness test results between 3.5 & 6N/mm	0
Damping and Elastic Properties (Log Decrement)	
Spacer demonstrates a Log Dec result lower than 0.40	30
Spacer demonstrates a Log Dec result between 0.40 & 0.499	15
Spacer demonstrates a Log Dec result of 0.50 or higher	0

Non-Elastomer Lined Clamp Spacer Damper Level 3 Scoring Criteria (Twin)

Electrical Resistance of Elastomeric Damping Elements	
The electrical resistance of damping elements below 0.8MΩ or above 24MΩ	30
The electrical resistance of damping elements is between 0.8 & 1MΩ or between 20 & 24MΩ	15
The electrical resistance of damping elements is between 1MΩ & 20MΩ	0
Longitudinal Clamp Slip	
The spacer clamps slipped at or below 2.5kN	30
The spacer clamps slipped between 2.5 & 3.95kN	15
The spacer clamps withstood a slip load of 5kN	0
Damping and Elastic Properties (Stiffness)	
The spacer demonstrates stiffness test results below 2.5 or above 7N/mm	20
The spacer demonstrates stiffness test results between 2.5 & 3.5N/mm or between 6 & 7N/mm	10
The spacer demonstrates stiffness test results between 3.5 & 6N/mm	0
Damping and Elastic Properties (Log Decrement)	
Spacer demonstrates a Log Dec result lower than 0.40	20
Spacer demonstrates a Log Dec result between 0.40 & 0.499	10
Spacer demonstrates a Log Dec result of 0.50 or higher	0

Vibration Damper Level 3 Scoring Criteria

Corrosion of Messenger Wire	
Messenger wire displays clear evidence of corrosion and is without grease	10
Messenger wire displays clear evidence of corrosion but still has some grease evident	5
Messenger wire does not display any evidence of corrosion	0
Damper Weight Corrosion	
Galvanising coating evidencing all sample areas with less than 50% coverage of 85µm	10
Galvanising coating evidencing all sample areas between 50.1 & 60% coverage of 85µm	7
Galvanising coating evidencing all sample areas between 60.1 & 79.99% coverage of 85µm	5
Galvanising coating evidencing all sample areas between 80 & 99.99% coverage of 85µm	2
Galvanising coating evidencing all sample areas with coverage of 100% or greater than 85µm	0
Conductor Clamp Slip	
Vibration damper slips at a load up to and including 50% of 2.5kN	20
Vibration damper slips at a load between 50.1 & 60% of 2.5kN	15
Vibration damper clamp slips at a load between 60.1 & 79.99% of 2.5kN	10
Vibration damper clamp slips at a load between 80 & 99.99% of 2.5kN	5
Vibration damper clamp maintains a slip load of 100% or greater than 2.5kN for more than 60 seconds	0
Damper Fatigue	
Vibration damper power dissipation is less than 50% of the specification	30
Vibration damper power dissipation is between 50 & 75% of the specification	25
Vibration damper power dissipation is between 75.1 & 99.9% of the specification	20
Vibration damper power dissipation is between 80 & 99.99% of the specification	10
Vibration damper power dissipation is equal to or greater than 100% of the specification	0
Attachment of Weight(s) to Messenger Wire	
Vibration damper weight maintains a pull off load less than 5kN	15
Vibration damper weight maintains a pull off load between 5 & 10kN	10
Vibration damper weight maintains a pull off load between 10 & 15kN	7.5
Vibration damper weight maintains a pull off load between 15 & 20kN	5
Vibration damper weight maintains a pull off load greater than 20kN	0
Attachment of Conductor Clamp to Messenger Wire	
Conductor clamp pulls off messenger wire at a load less than 50% of 1.5kN	15
Conductor clamp pulls off the messenger wire at a load between 50.1 & 60% of 1.5kN	10
Conductor clamp pulls off the messenger wire at a load between 60.1 & 79.99% of 1.5kN	7.5
Conductor clamp pulls off the messenger wire at a load between 80 & 99.99% of 1.5kN	5
Conductor clamp maintains a pull off load greater than 1.5kN for more than 60 seconds	0

Insulator Level 2 Scoring Criteria (Porcelain)

Resistance Test	
The insulator is above the minimum resistance values of 15MΩ	30
The insulator is below the minimum resistance values of 15MΩ	0
Insulator Security Clip	
Insulator security clip damaged or missing	10
Insulator security clip present and undamaged	0
Diameter of Insulator Pin	
Pin diameter greater than 10% of nominal dimension by design: 80kN – equal to or less than 14.22mm or equal to or greater than 18.59mm 125kN - equal to or less than 17.72mm or equal to or greater than 22.99mm 190 & 300kN - equal to or less than 21.23mm or equal to or greater than 27.37mm 400kN - equal to or less than 24.74mm or equal to or greater than 31.75mm	30
Pin diameter up to +/- 10% of nominal dimension by design: 80kN - between 14.22 & 15.79mm or 17.01 & 18.58mm 125kN - between 17.73 & 19.69 or 21.01 & 22.98mm 190 & 300kN – between 23.60 & 25.0mm 400kN – between 27.50 & 29.0mm	15
Pin diameter within tolerances of nominal dimensions by design: 80kN - between 15.80 & 17.00mm 125kN – between 19.70 & 21.0mm 190 & 300kN - between 23.60 & 25.0mm 400kN – between 27.50 & 29.0mm	0
Cracks in Insulator Shell	
Shell displays evidence of cracks	10
Shell does not display evidence of cracks	0
Cracks in Insulator Cement	
Insulator cement shows evidence of cracks	10
Insulator shell does not display evidence of cracks	0
Evidence of Flashover	
Shell displays evidence of flashover (burn marks on shell or damaged glaze)	10
Shell does not display evidence of flashover	0

Insulator Level 2 Scoring Criteria (Glass)

Insulator Security Clip	
Insulator security clip damaged or missing	10
Insulator security clip present and undamaged	0
Diameter of Insulator Pin	
Pin diameter greater than 10% of nominal dimension by design: 80kN – equal to or less than 14.22mm or equal to or greater than 18.59mm 125kN - equal to or less than 17.72mm or equal to or greater than 22.99mm 190 & 300kN - equal to or less than 21.23mm or equal to or greater than 27.37mm 400kN - equal to or less than 24.74mm or equal to or greater than 31.75mm	40
Pin diameter up to +/- 10% of nominal dimension by design: 80kN - between 14.22 & 15.79mm or 17.01 & 18.58mm 125kN - between 17.73 & 19.69 or 21.01 & 22.98mm 190 & 300kN – between 23.60 & 25.0mm 400kN – between 27.50 & 29.0mm	20
Pin diameter within tolerances of nominal dimensions by design: 80kN - between 15.80 & 17.00mm 125kN – between 19.70 & 21.0mm 190 & 300kN - between 23.60 & 25.0mm 400kN – between 27.50 & 29.0mm	0
Cracks in Insulator Cement	
Insulator cement shows evidence of cracks	25
Insulator shell does not display evidence of cracks	0
Evidence of Flashover	
Shell displays evidence of flashover (burn marks or etching on the glass)	25
Shell does not display evidence of flashover	0

Conductor & Insulator Fittings Level 2 Scoring Criteria

Shackle & Ball Fittings (Wear) Reduction in sectional area of the load bearing points of the connection between the Shackle & Ball Ended Eyelink or the Shackle or Ball Clevis landing bolt	
Shackle & Ball / Clevis Fitting interface wear (Up to 5% loss of material) 70kN Material interface thickness is equal to or more than 34.20mm 125kN Material interface thickness is equal to or more than 39.90mm 190kN Material interface thickness is equal to or more than 44.65mm or Shackle Landing Bolts 70kN Shackle Bolt Diameter is 15.20mm or above 125kN Shackle Bolt Diameter is 19.00mm or above 190kN Shackle Bolt Diameter is 20.90mm or above 300 & 400kN Ball Clevis Bolt Diameter is 28.50mm or above	0
Shackle & Ball / Clevis Fitting interface wear (Between 5% & 10% loss of material) 70kN Material interface thickness between 32.40 & 34.10mm 125kN Material interface thickness between 37.80mm & 39.80mm 190kN Material interface thickness between 42.30mm & 44.64mm or Shackle Landing Bolts 70kN Shackle Bolt Diameter is between 14.40mm & 15.19mm 125kN Shackle Bolt Diameter is between 17.00mm & 18.99mm 190kN Shackle Bolt Diameter is between 19.10 & 19.80mm 300 & 400kN Ball Clevis Bolt Diameter is between 27.00mm & 28.40mm	15
Shackle & Ball / Clevis Fitting interface wear (Between 10% to 20% loss of material) 70kN Material interface thickness between 28.80 & 34.00mm 125kN Material interface thickness between 33.60mm & 37.70mm 190kN Material interface thickness between 37.60mm & 44.63mm or Shackle Landing Bolts 70kN Shackle Bolt Diameter is between 12.80mm & 14.39mm 125kN Shackle Bolt Diameter is between 16.00mm & 16.99mm 190kN Shackle Bolt Diameter is between 17.60mm & 19.00mm 300 & 400kN Ball Clevis Bolt Diameter is between 24.00mm & 28.30mm	30
Shackle & Ball / Clevis Fitting interface wear (Between 20% to 30% loss of material) 70kN Material interface thickness between 26.20mm to 28.70mm 125kN Material interface thickness between 29.40mm & 32.50mm 190kN Material interface thickness between 32.90mm & 37.50mm or Shackle Landing Bolts 70kN Shackle Bolt Diameter is between 11.20mm & 12.70mm 125kN Shackle Bolt Diameter is between 14.00mm & 15.90mm 190kN Shackle Bolt Diameter is between 15.40mm & 17.50mm 300 & 400kN Ball Clevis Bolt Diameter is between 21.00mm & 23.99mm	45
Shackle & Ball / Clevis Fitting interface wear (Between 30% to 40% loss of material) 70kN Material interface thickness between 21.60mm & 25.10mm 125kN Material interface thickness between 25.20mm & 29.30mm 190kN Material interface thickness between 37.40mm & 28.20mm or Shackle Landing Bolts 70kN Shackle Bolt Diameter is between 9.60mm & 11.10mm 125kN Shackle Bolt Diameter is between 12.00mm & 13.90mm 190kN Shackle Bolt Diameter is between 13.20mm & 17.60mm 300 & 400kN Ball Clevis Bolt Diameter is between 18.00mm & 20.99mm	60
Shackle & Ball / Clevis Fitting interface wear as detailed below (Above 40% loss of material) 70kN Material interface is less than 21.50mm 125kN Material interface is less than 25.20mm 190kN Material interface is less than 28.20mm or Shackle Landing Bolts 70kN Shackle Bolt Diameter is below 9.50mm 125kN Shackle Bolt Diameter is below 11.90mm 190kN Shackle Bolt Diameter is below 17.70mm 300 & 400kN Ball Clevis Bolt Diameter is below 18.00mm	80

Shackle & Ball Fittings (Corrosion)	
Clean – Fitting and attachment bolt clean and still evidencing good galvanising coverage	0
Light - Corrosion evident up to 50% of the component surface area	5
Heavy - Corrosion evident across more than 50% of the component surface area	7.5
Pitted – Corrosion has developed to a stage where pitting of the component is evident	10
Arc Horns (Corrosion)	
Clean – Fitting and attachment bolt clean and still evidencing good galvanising coverage	0
Light - Corrosion evident up to 50% of the component surface area	5
Heavy - Corrosion evident across more than 50% of the component surface area	7.5
Pitted – Corrosion has developed to a stage where pitting of the component is evident	10

Suspension Clamp Straps & Attachment Bolt / Dowel Diameter (Wear) The loss of material on the suspension clamp strap bearing point and attachment bolt diameter	
<u>Up to 5% change in diameter</u> 18mm Strap Bolt Hole Diameter of hole in straps is between 18.00mm & 18.90mm 22mm Strap Bolt Hole Diameter of hole in straps is between 22.00mm & 23.10mm or 16mm Landing Bolt Diameter of bolt is between 15.20mm & 16.00mm 20mm Landing Bolt Diameter of bolt is between 19.00mm & 20.00mm	0
<u>Between 5% & 10% Change in diameter</u> 18mm Strap Bolt Hole Diameter of hole in straps is between 19.00mm & 19.80mm 22mm Strap Bolt Hole Diameter of hole in straps is between 22.00mm & 23.10mm or 16mm Landing Bolt Diameter of bolt is between 14.40mm & 15.10mm 20mm Landing Bolt Diameter of bolt is between 18.00mm & 18.90mm	15
<u>Between 10 & 20% Change in diameter</u> 18mm Strap Bolt Hole Diameter of hole in straps is between 19.00mm & 21.60mm 22mm Strap Bolt Hole Diameter of hole in straps is between 23.20mm & 24.20mm or 16mm Landing Bolt Diameter of bolt is between 15.00mm & 12.80mm 20mm Landing Bolt Diameter of bolt is between 16.00mm & 17.90mm	30
<u>Between 20 & 30% Change in diameter</u> 18mm Strap Bolt Hole Diameter of hole in straps is between 21.70mm & 23.40mm 22mm Strap Bolt Hole Diameter of hole in straps is between 24.30mm & 28.60mm or 16mm Landing Bolt Diameter of bolt is between 12.70mm & 11.20mm 20mm Landing Bolt Diameter of bolt is between 14.00mm & 15.90mm	45
<u>Between 30 & 40% Change in diameter</u> 18mm Strap Bolt Hole Diameter of hole in straps is between 23.50mm & 25.20mm 22mm Strap Bolt Hole Diameter of hole in straps is between 28.70mm & 30.80mm or 16mm Landing Bolt Diameter of bolt is between 11.10mm & 9.60mm 20mm Landing Bolt Diameter of bolt is between 12.00mm & 13.90mm	60
<u>Above 40% Change in diameter</u> 18mm Strap Bolt Hole Diameter of hole in straps is above 25.10mm in diameter 22mm Strap Bolt Hole Diameter of hole in straps is above 30.80mm in diameter or 16mm Landing Bolt Diameter of bolt is less than 9.60mm 20mm Landing Bolt Diameter of bolt is less than 12.00mm	80

Suspension Clamp Straps & Trunnion Interface (Wear) The loss of material on the suspension clamp strap and Trunnion Interface	
Up to 5% wear Up to 5% loss of section on the suspension clamp trunnion or up to 5% wear on the suspension clamp landing strap hole that supports the trunnion	0
Between 5 & 10% wear Between 5 & 10% loss of section on the suspension clamp trunnion or Between 5 & 10% wear on the suspension clamp landing strap hole that supports the trunnion	15
Between 10 & 20% wear Between 10 & 20% loss of section on the suspension clamp trunnion or Between 10 & 20% wear on the suspension clamp landing strap hole that supports the trunnion	30
Between 20 & 30% wear Between 20 & 30% loss of section on the suspension clamp trunnion or Between 20 & 30% wear on the suspension clamp landing strap hole that supports the trunnion	45
Between 30 & 40% wear Between 30 & 40% loss of section on the suspension clamp trunnion or Between 30 & 40% wear on the suspension clamp landing strap hole that supports the trunnion	60
More than 40% wear Above 40% loss of section on the suspension clamp trunnion or Above 40% wear on the suspension clamp landing strap hole that supports the trunnion	80
Compression Anchor Clamps	
High resistance joint identified in the main compression element of the joint with resistance readings up to 20% higher than the permitted maximum detailed in TGN 325	10
High resistance joint identified in the main compression element of the joint with resistance readings between 20% & 30% higher than the permitted maximum detailed in TGN 325	20
High resistance joint identified in the main compression element of the joint with resistance readings between 30% & 40% higher than the permitted maximum detailed in TGN 325	40
High resistance joint identified in the main compression element of the joint with resistance readings between 40% & 50% higher than the permitted maximum detailed in TGN 325	60
High resistance joint identified in the main compression element of the joint with resistance readings 50% or higher than the permitted maximum detailed in TGN 325	80
Wedge Anchor Clamps	
Wedge clamp is in the correct position and the assembly is fully intact without conductor damage	0
Wedge clamp is in the correct position and the assembly is fully intact with evidence of conductor damage of up to 3 strands damaged or broken	10
Wedge clamp has slipped out of position and has caused conductor damage	20
Wedge clamp is open and or broken and has caused conductor damage of 4 or more strands	30

14 Long Term Risk Benefit – Immortal Model

The measurement of the Long Term Risk Benefit (LTRB) expresses the perceived benefit of undertaking a particular intervention, and the relative ranking of risk-benefit as a result.

This section describes the concepts of NGET's implementation of Long term risk benefit.

For RIIO-T3, NGET has adopted an Immortal model; which addresses certain issues encountered with the older Analytical, Survival model used for RIIO-T2. The change aligns NGET's methods to those used by Electricity Distribution.

The immortal model assumes that the original asset continues to function for the entire time horizon. Risk will rise and eventually cap-out as the probability of failure tends to 1 (100%). As an asset's condition deteriorates, its monetised risk increases. When an intervention is carried out, the risk is mitigated; either by replacement or refurbishment. Assuming a replacement is like-for-like, the consequences of failure of the new or refurbished asset would be identical to the original, while the probability of failure is reduced.

Monetised risk is determined for all assets per the NARA and can be calculated for multiple years on the assumption that equivalent age increases by one per calendar year.

The LTRB time horizon of 45 years is specified for asset replacements, and 20 years for circuit breaker refurbishment.

Risk is calculated for each year, and a discount factor is applied to each year per the definitions given in *Intergenerational wealth transfers and social discounting : Supplementary Green Book Guidance*; that is, a discount factor of 3.5% is applied in years 1-30, and 3% thereafter.

The Long Term Risk Benefit is the sum of those risks over the specified time horizon.

$$Single\ Asset\ LTRB = \sum_{1}^{n} R * Df$$

Equation 14.1

Where n is the upper limit of the time horizon, R is the monetised risk for specified year and scenario, and Df is the discount factor applied.

The observant will note that an asset planned for e.g. 2028, but completed in 2031 will exhibit greater LTRB for the later intervention date. In order to eliminate the potential to incentivise late delivery of work, all LTRB outputs for RIIO-T3 are expressed as if the intervention occurs in 2031; this is referred to as the Baseline LTRB Output. The time horizons considered therefore, are always 2031-2076 for replacements or 2031-2051 for circuit breaker refurbishments.

In order to achieve intended asset lifetimes, this method assumes that maintenance activities are being completed as required. Maintenance related failure modes are included in LTRB determination. The timing of maintenance has no bearing on decisions pertaining to replacement of a given asset. This aligns the calculation of NGET's LTRB to comparable terms to those used by SPT and SHE-T, and also resolves model volatility issues arising from timing of maintenance.

15 Differences With Other Network NARA

The NGET NARA differs in some areas from that employed by other TO's and DNOs. This section is intended to highlight the important differences, reasons for them, and possible barriers to alignment.

NGET NARA differs in certain elements from DNO, Scottish ETOs and the Gas TO methodologies. While assessment and treatment of risk is similar, there are differences in the construction of networks and organisation's risk appetite that can influence how risk is modelled and treated. Many other networks include extensive radial connections, with little redundancy and covering long distances. The NGET NARA would evaluate such a connection to be a high if not very high risk. The disparity in number of customers connected per asset, time to intervene, and supply chain considerations mean that asset management decisions and strategy for managing that connection differ. This is reflected in the differences between the different network NARAs.

With such varied types of connection and asset solutions; mitigations to risk are equally varied. Other TOs and DNOs routinely use mobile generation to either enable works or provide standby capability in event of failure. Such a solution is not practical for the quantities of energy carried on a typical NGET asset. Instead, the power must be re-routed to satisfy demand. Maintaining a reliable enough network to absorb potential faults and failures is reflected in both the System Design philosophy expressed in the SQSS (Security & Quality of Supply Standard) and the NGET NARA.

Sections 8.1.3 and 8.1.4 of NGET NARA discuss the probability and duration of fault, important parameters in determination of system consequences. These are influenced by the physical design and operational strategies of respective networks, for example the time to deploy personnel to a remote location has bearing on the time to recover post-fault. All three TO's have used a comparable approach to system consequences modelling; with differences in the assumptions arising from the differences in geography, system design and operational strategies employed.

We have consulted with the SPT and SHE-T to align the financial consequences associated with unit replacement, which is hoped will improve the comparability of the risk output between networks.

Concerning Failure Modes and Effects Analysis, NGET may have to give consideration to small asset populations; in some cases as low as one asset. This is in contrast to the DNO's CNAIM model, which enjoys the benefit of large asset populations, both nationally and globally. Deriving useful statistics from small populations is somewhat challenging, and instead necessitates the use of expert knowledge and judgement to populate.

The SPT and SHE-T NARA has a mechanism whereby any "unclassified" issue can be assigned an arbitrary EoL-modifier in response. There was no equivalent to this in the NGET NARA, noting that it was always understood that the NARA could not cover every possible set of conditions warranting intervention. That said, we have for issue 7 added a discretionary scoring parameter to cable systems due to the potential for one-off defects in this asset category that otherwise defy attempts at classification. The use of this parameter must of course be accompanied by appropriate engineering justification.

During RIIO-T1 closeout, NGET noted differences in approaches to overhead line modelling compared with the SPT and SHE-T. NGET models risk by Routelet, that is, multiple spans usually of the same construction treated as a single asset in the risk model. Whereas SPT and SHE-T report OHL risk at a per-span level. There is no specific barrier to aligning methodologies in this regard, though NGET note that decisions to carry out capital interventions are not taken at the per-span level.

An objective of calculating risk is as a decision support tool to inform intervention strategies. Both the NGET and SPT and SHE-T NARAs are valid methods for doing this; designed in line with respective network's risk appetites. Despite efforts to align in many areas, a direct comparison of outputs from one network to another is still not without difficulties, for they are built with different assumptions based on their own organisation's risk appetite.

16 NARM Development

NARM and the Common Methodology are periodically reviewed in order to satisfy License Special Condition 9.2, and further the ongoing improvement of the Common Methodology and NARA in pursuit of the NARM Objectives.

Early 2022 both the TO's and Ofgem conducted a review of priority areas for development of both the Common Methodology and NARM. Priorities for development were jointly agreed, as were the timescales for development.

Category 1 modifications were incorporated into issue 6 and 6.1 of NGET NARA. These include improvements to the documentation of the Calibration, Testing and Validation processes; improvements to document transparency by consolidation of the Licensee-Specific Appendices wherever possible, improvement of the stakeholder engagement strategy, and a review of the differences, and possible barriers to alignment of different TO NARA.

NARA 7 incorporates the Category 2 modifications proposed, in anticipation of use in the RIIO-T3 price control.

Guidance Notes and Appendices

REFERENCES

- ISO 55000 Asset Management standards
- BS EN 60812:2006 Analysis Techniques for System Reliability
- AA1000 Stakeholder Engagement Standard (AccountAbility, 2015)
- Intergenerational wealth transfers and social discounting: Supplementary Green Book
- CIGRE TB 309 Asset Management of Transmission Systems & Associated CIGRE Activities
- CIGRE TB 858 Asset Health Indices for Equipment in Existing Substations
- CIGRE TB 912 Condition evaluation and lifetime strategy of HV cable systems

Appendix A. Assumptions Log

NGET -
Assumptions Log - C

Appendix B. Calibration, Testing and Validation Activity Summary

While implementing the NARM Methodology, NGET conducted detailed Calibration, Testing and Validation (CTV) to ensure achievement of the NARM Methodology Objectives. A summary of the activities undertaken as part of Calibration, Testing and Validation (CTV) of the NARM Methodology are tabulated below.

Element	Aim	Technique	Pass Measure
Further explanation of EoL modifier methodology with references	Explanation of rational that has been followed in determining functional form utilised within the EoL modifier approach. Reference where possible.	Workshops, expert review, reference industry standard approaches	A document supporting the formulae in the EoL modifier methodology - Approved by internal expert reviewers
End of life failure mode	To confirm the derivation of Asset Health Index / EoL modifier is in line with the NARM Methodology	Review the implementation of all elements of EoL modifier derivation, verify that implementation is correct using manual or spreadsheet calculation where necessary	Verification that all elements of the derivation of the probability of failure are implemented as described in the Methodology.
All Licensees - EoL modifier comparison	Compare EoL Modifiers for a sample of assets across each of the TNOs	Comparability testing between the TNOs via sampling of assets across a range of EoL modifiers. Subject matter experts to assess outputs from this analysis to understand differences and ensure comparability.	Meets licence requirements - model provides a like for like comparison of EoL modifiers across different categories of assets
FMEA output: failure mode, failure rate (indicative), frequency of events (indicative), and detection; probability of events	To use the failure, fault, and defect database to validate those failure modes used in the FMEA workshops which will validate credible probability of failure. Validate probability of events using fault, failure, and defects data	Data cleanse and data manipulation, guided by subject matter expert	Results from the fault, failure, and defect database is compatible with the expected output of events from FMEA/risk model
End of life failure mode	Where possible, validate the end-of-life failure mode for each asset type using data-driven methods	Justify end of life (EoL) failure modes using expert knowledge or/and data driven methods where appropriate. Calculate PoF and compare to expected number of replacements.	PoF and expected number of events agree. Validation provided for EoL FMs

Disruptive failure and Implied Probability of Disruptive Failure	While the probability of disruptive failures used, the failure database should be used to validate the probabilities	Statistical analysis, where data is available, and implied failure probability when data is not available, reviewed by engineering experts	The disruptive failure mode is appropriately addressed in the methodology with validated probabilities, in order to correctly model the scenarios associated with the disruptive failures
Assumption of independence Data needed to model inter-dependence The assumption of mutual exclusivity for failure modes	Test the assumptions of inter-dependence when the model combines different failure modes and events together using data facilitated by engineering knowledge and experience. The model assumes the failure modes are independent but not mutually exclusive, i.e. in theory those modes can fail at the same time. Reviewing the definitions and physical process of the failure modes in the FMEA spreadsheet.	Data categorisation, facilitated by engineering knowledge. Review in the context of FMEA output validation. Tests performed to confirm that those are reflected in the model workshops, subject matter experts and collective opinion	The assumptions are shown to be valid or non-material
Survival curve EoL modifier validation	Validate that the relationship between EoL modifier score and age has expected relationship at population level for each type of asset then Calibrate parameters in the EoL modifier to PoF mapping process using these outputs. Iterate this process as appropriate.	Translate end of life scores into survival curves and then use this to compare with the anticipated asset life, which is based on data, subject matter expert opinion and industrial best practice. Align the different models and also align the models with data/engineering experience as detailed in the above two cases	Reasonable match to existing policy with differences understood and where possible quantified. The expected number of end of life related replacement events agree with our historical replacement data.

Cost of (material) consequence - the model	Review the process when introducing criticality (or any other asset specific information) into the cost of (material) consequence. At the same time, make sure the current criticality definition is appropriately translated into the probability of (material) consequence.	Independent review and comparison study, e.g. the definitions between the cost of (material) consequence and criticality	The definitions and approach are compatible and can be justified. And the cost of material consequence is compatible with the current criticality data (for example, criticality is currently represented by exposure and vulnerability, which might be duplicated with the probability of material consequence)
Cost of (material) consequence - the values for the disruptive failure.	Make sure the cost of (material) consequence values are in the right magnitude of order, and this exercise also helps to pin down the most suitable values that can be used for the monetised risk modelling	Data cleanse and data manipulation, comparison of expected costs of events with cost data where possible	The cost data supports the values of the cost of financial consequence data retained by the TOs
Financial Consequence	Validate the financial consequence values using cost data. Calibrate if validation fails.	Data cleanse and data manipulation, statistical analysis	The cost data supports the values of the cost of financial consequence data
Safety and environmental consequences	To validate the safety and environmental consequence values that are proposed in the NARM methodology, and calibrate if validation fails.	Compare the probability of events and cost of events from the modified NARM methodology with the historical events over the whole network for environmental and safety related events	The comparison study provides consistent outcomes (from the model and the historical records)
The return to service (RTS) time - system consequence	To validate the return to service time that is used to calculate the system consequence; to review and test the assumptions over the return to service time proposed in the FMEA workshops	Review the assumptions with the modelling and data, e.g. the RTS modelling use a single value to represent all the events/assets of this type; the RTS time is insensitive to asset condition, etc.	Those assumptions are supported by the data

Direct customer connection - system consequence	To validate the cost of system consequence toward the direct customer connection	Compare the probability of events and cost of events from the modified NARM methodology with the historical events over the whole network for disconnection of customers (supply and demand sides) related events	The total system consequence risk value derived from the NARM methodology has reasonable agreement with the cost of historical customer disconnection events.
Customer disconnections within System Consequence	To validate the probability and durations of customer disconnections against those predicted by another tool used to calculate the likelihood of customer disconnections, TRIP.	Calculate the probability and duration of customer disconnection for three customer sites using both tools and compare results.	The results align, to a reasonable degree, taking into account the differences in scope of the tools.
Data Load and Processing Routines	Ensure base data sets used by the Risk Model are correctly loaded and processed. Any corrupted /incorrect data is explicitly identified.	Unit test of data load procedures and validation against known data sets	Pass of Unit Testing. Data loaded of the correct dtypes. Incorrect data identified and exceptions raised.
Generation of Probability Distributions and Parameters	Generation of parameters for various distributions and validation of probability values for each distribution type	Unit testing against known results for each distribution type ensuring outputs of the model align with reference values	Model outputs agree with reference inputs.
Generation of PoF by Failure Mode and Asset Type and Generation of Effective DataFrames for each Asset	To confirm the calculations for the Probability of Failure (PoF) are correct	For a sample of the assets, ensure that the PoF calculations are correct, using manual or spreadsheet calculation where necessary	Ensure that the Asset.pof dataframe entirely matches the manual calculations, in all years, for all of the assets in the sample
Generation of PoE by Failure Mode and Asset Type	To confirm the calculations for the Probability of Event (PoE) are correct	For a sample of the assets, ensure that the PoE calculations are correct, using manual or spreadsheet calculation where necessary	Ensure that the Asset.poe dataframe entirely matches the manual calculations, in all years, for all of the Asset/Event combinations in the sample
Generation of Monetised Risk Scores	To confirm the calculations for the Monetised Risk Scores (Asset.wtd_risks) are correct	For a sample of the assets, ensure that the Monetised Risk Score calculations are correct, using manual or spreadsheet calculation where necessary	Ensure that the Asset.wtd_risks dataframes entirely matches the manual calculations, in all years, for all of the Assets in the sample

Table 59